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DETAILED COST ESTIMATES FOR ADVANCED EFFLUENT DESULFURIZATION PROCESSES

TENNESSEE VALLEY AUTHORITY

PREPARED FOR
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A detailed, segmented, highly visible cost comparison of the five leading stack gas desulfurization processes was conducted. Using data available in late 1973, complete economic evaluations were prepared for limestone slurry scrubbing, lime slurry scrubbing, magnesia slurry scrubbing - regeneration to sulfuric acid, sodium solution scrubbing - SO_2 reduction to sulfur, and catalytic oxidation (Cat-Ox). Assuming the process technology to be proven in application, a prescribed set of representative power plant, process design, and economic premises was established. For each process design, projections are included for a base case (500-MW, 3.5% S in coal, new unit) and 16 other variations in power unit size, fuel type (coal or oil), sulfur in fuel, unit status (new vs. existing), solids disposal method (off-site vs. on-site ponding), and SO_2 removal (80% vs. 90%). Capital investment, annual operating costs (7,000 hr/yr) and lifetime operating costs (over a 30-year declining operating profile) were estimated for the base case and each variation. Using sensitivity analysis, effects of variations in energy costs, raw material costs, maintenance costs, cost of capital, operating labor cost escalation, and net sales revenue were studied. A 3-year construction schedule ending in mid-1975 is assumed for a midwestern location. Investment costs (mid-1974 dollars) can be scaled or altered to reflect any predictable project schedule, escalation rate, or location. Definition of the systems estimated, sources of cost data, and recommended equipment size-cost scale factors are given.

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a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air pollution	Boiler	Air pollution control	7 A
Chemical reactions	Design	Stationary sources	7 C
Desulfurization	Fuel	Scrubbing - regeneration	7 D
Economic analysis	Sulfur dioxide	Limestone slurry	13 B
Capitalized costs		Lime slurry	14 A
Operating costs		Magnesia slurry - regeneration	21 D
Washing		Sodium solution - SO_2 reduction	
Scrubbing		Catalytic oxidation	
Regeneration (engineering)			

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A detailed, segmented, highly visible cost comparison of the five leading stack gas desulfurization processes was conducted. Using data available in late 1973, complete economic evaluations were prepared for limestone slurry scrubbing, lime slurry scrubbing, magnesia slurry scrubbing - regeneration to sulfuric acid, sodium solution scrubbing - SO_2 reduction to sulfur, and catalytic oxidation (Cat-Ox). Assuming the process technology to be proven in application, a prescribed set of representative power plant, process design, and economic premises was established. For each process design, projections are included for a base case (500-MW, 3.5% S in coal, new unit) and 16 other variations in power unit size, fuel type (coal or oil), sulfur in fuel, unit status (new vs. existing), solids disposal method (off-site vs. on-site ponding), and SO_2 removal (80% vs. 90%). Capital investment, annual operating costs (7,000 hr/yr) and lifetime operating costs (over a 30-year declining operating profile) were estimated for the base case and each variation. Using sensitivity analysis, effects of variations in energy costs, raw material costs, maintenance costs, cost of capital, operating labor cost escalation, and net sales revenue were studied. A 3-year construction schedule ending in mid-1975 is assumed for a midwestern location. Investment costs (mid-1974 dollars) can be scaled or altered to reflect any predictable project schedule, escalation rate, or location. Definition of the systems estimated, sources of cost data, and recommended equipment size-cost scale factors are given.

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Executive Summary

After several years of intensive process development, several power plant stack gas SO_2 removal systems are now advancing from the pilot-plant stage to demonstration-scale applications. With the installation of these demonstration-size facilities on power units around the United States, it should now be possible to more accurately predict their costs so that utility executives can better choose between alternatives.

Under the provisions of the Clean Air Act of 1967 and its 1970 ammendments, the Federal Environmental Protection Agency has funded research and development on SO_2 removal processes including several conceptual design and cost studies. In these earlier efforts, many design assumptions were necessary and cost estimate accuracy was questionable since technology was in an infant state and available design data were limited. Equipment costs were sketchy since most vendors had yet to fabricate and erect the large gas scrubbing devices required for full-scale systems. Furthermore, very little corrosion data were available to predict materials of construction for the services involved. In many cases, optimism of the process developers tended to maximize process potential and to minimize problem areas such as erosion, scaling, solids disposal, sulfite oxidation, mist elimination, gas reheat, operational turndown, and pH control.

Finally, after many pilot-plant tests and both encouraging and disappointing experiences, five processes have emerged from the many proposed as the leading systems for demonstration. These are the limestone slurry process and the lime slurry process, both of which are throwaway systems (no salable byproduct), and the magnesia slurry - regeneration, sodium solution scrubbing - SO_2 reduction, and catalytic oxidation processes which produce salable sulfuric acid or elemental sulfur. In cooperation with participating utilities and process developers, EPA is currently funding large-scale test and demonstration projects on each of these processes. The processes and the associated projects are shown in table S-1.

Now that many of the unknowns for these systems have surfaced, remedies been prescribed, and large-scale projects started, more accurate assessment of process costs should be possible. The objective of this study is to prepare a set of highly visible,detailed, capital and operating cost estimates for comparison of the five leading processes on a common uniform basis.

PROCESS DEFINITION

A brief description of the subject processes and the organizations supplying representative system data for this

Table S-1. EPA-Sponsored Stack Gas Desulfurization Demonstration Systems

EPA-sponsored process (byproduct)	Cooperating utility	Process developer	Location	Unit size and type	Expected startup
Limestone slurry scrubbing (sludge)	TVA	Bechtel and others	Shawnee unit 10 Paducah, Ky.	10 MW coal	Under way
Lime slurry scrubbing (sludge)	TVA	Chemico, Bechtel, and others	Shawnee unit 10 Paducah, Ky.	10 MW coal	Under way
Magnesia slurry scrubbing - regeneration (98% sulfuric acid)	Boston Edison	Chemico-Basic	Mystic Station 6 Boston, Mass.	155 MW oil	Completed
Catalytic oxidation (reheat) (80% sulfuric acid)	Illinois Power	Monsanto	Wood River Station 4 East Alton, Ill.	110 MW coal	Mid-1974
Sodium scrubbing - regeneration (sulfur)	Northern Indiana Public Service Co.	Davy Powergas Allied Chemical	D. H. Mitchell Station 11 Gary, Ind.	115 MW coal	Late 1975

study are given below. The process data represent the state of technology in late 1973.

1. *Limestone slurry scrubbing*—Stack gas is washed with a recirculating slurry (pH of 5.8-6.4) of limestone and reacted calcium salts in water using a two-stage (venturi and mobile bed) scrubber system for particulate and SO_2 removal. Limestone feed is wet ground prior to addition to the scrubber effluent hold tank. Calcium sulfite and sulfate salts are withdrawn to a disposal area for discard. Reheat of stack gas to 175°F is provided. Design is based on data taken from EPA-TVA-Bechtel Shawnee test program.
2. *Lime slurry scrubbing*—Stack gas is washed with a recirculating slurry (pH of 6.0-8.0) of calcined limestone (lime) and reacted calcium salts in water using two stages of venturi scrubbing. Lime is purchased from "across the fence" calcination operation, slaked, and added to both circulation streams. Calcium sulfite and sulfate are withdrawn to a disposal area for discard. Reheat of stack gas to 175°F is provided. Design is based on data provided by Chemical Construction Corporation (Chemico).
3. ***Magnesia** slurry scrubbing - regeneration of H_2SO_4*—Stack gas is washed using two separate stages of venturi scrubbing—the first utilizing water for removal of particulates, and the second utilizing a recirculating slurry (pH 7.5-8.5) of magnesia (MgO) and reacted magnesium-sulfur salts in water for removal of SO_2. Makeup magnesia is slaked and added to cover only handling losses since sulfates formed are reduced during regeneration. Slurry from the SO_2 scrubber is dewatered, dried, calcined, and recycled during which concentrated SO_2 is evolved to a contact sulfuric acid plant producing 98% acid. Reheat of stack gas to 175°F is provided. Design is based on data supplied by Chemico-Basic Corporation.
4. *Sodium solution scrubbing - SO_2 regeneration and reduction to sulfur*—Stack gas is washed with water in a venturi scrubber for removal of particulates and then washed in a valve tray scrubber with a recirculating solution of sodium salts in water for SO_2 removal. Makeup sodium carbonate is added to cover losses due to handling and oxidation of sodium sulfite to sulfate. Sodium sulfate crystals are purged from the system, dried, and sold. Water is evaporated from the scrubbing solution using a single-effect evaporator to crystallize and thermally decompose sodium bisulfite, driving off concentrated SO_2. The resulting sodium sulfite is recycled to the scrubber and the SO_2 is reacted with methane for reduction to elemental sulfur. Reheat of stack gas to 175°F is provided. The regeneration and reduction areas are designed for 100% of power plant load. Design for the scrubbing - evaporator - crystallizer system is provided by Davy Powergas, Inc. (Wellman-Lord process), and data for the SO_2 reduction unit are provided by Allied Chemical Corporation.
5. *Catalytic oxidation*—In the "integrated" design, 890°F stack gas is first cleaned of particulates (to 0.005 gr/scf) by a high-temperature electrostatic precipitator; then, the SO_2 is catalytically converted to SO_3 and available excess heat is recovered. For a "reheat" design, stack gas at 300°F is reheated to 890°F by heat exchangers and direct fuel oil firing prior to conversion of SO_2 to SO_3. In either case, the SO_3 reacts with moisture in the stack gas to form H_2SO_4 mist which is scrubbed in a packed tower using a recirculating acid stream to yield 80% acid. Mist is removed by a Brink mist eliminator and the clean 254°F gas is exhausted to the stack. Both integrated and reheat designs are based on data supplied by Monsanto Company, developers of the Cat-Ox process.

Representative flow diagrams, material balances, control diagrams, plant layouts, and equipment arrangements are included in the report for the base case (new 500-MW coal-fired unit, 3.5% S in fuel, 90% SO_2 removal) of each process. Together with detailed equipment descriptions, this background defines the systems estimated.

MAJOR DESIGN AND COST FACTORS

From previous economic studies, the following factors are considered to be the most important; therefore, their effects on SO_2 control costs are defined.

1. *Project schedule and location*—Project assumed to start in mid-1972 with 3-year construction period ending mid-1975. Midpoint of construction costs mid-1974, *Chemical Engineering* Cost Index—160.2. Startup—mid-1975. A midwestern plant location is assumed.
2. *Power unit size*—Costs for three unit sizes—200, 500, 1,000-MW—are projected.
3. *Fuel type*—Systems for both coal- and oil-fired units are costed: coal—12,000 Btu/lb, 12% ash, oil—18,500 Btu/lb, 0.1% ash.
4. *Sulfur content of fuel*—Costs for three sulfur levels are evaluated for each fuel—2.0%, 3.5%, and 5.0% for coal; 1.0%, 2.5%, and 4.0% for oil.
5. *Plant status*—Although systems for both new and existing power units are evaluated, only a simple, moderately difficult (scrubbing system installed in vacant space beyond the stack) retrofit is estimated since such systems can vary over such a wide range of configurations and restrictions. New units are

designed for a 30-year life, 127,500 hours of operation. Costs for new and existing systems are not directly comparable.

6. *SO_2 removal*—Since all five processes are capable of 90% SO_2 removal and future demands for emission control may exceed present standards, 90% removal is specified as the base value. For those processes in which cost effective design changes could be identified, 80% removal is also projected.
7. *Particulate removal*—Costs are included for 98.7% particulate removal (to meet EPA standard of 0.1 lb/million Btu heat input) on new coal-fired systems except Cat-Ox which requires 99.9% removal (for process reasons, restricted to 0.005 gr/scf prior to entering converter). Existing units are assumed to be already equipped with 98.7% electrostatic precipitators; therefore, only incremental additional precipitator is required. Because of this provision, the investment and operating cost results for existing coal-fired systems appear lower than for new units. To cover this disparity, a special case is examined where full particulate removal must be added to an existing unit. Oil-fired units do not require dust removal facilities.
8. *Raw materials and catalysts*—Assuming startup in 1975, midwestern 1975 delivered prices are projected and sensitivity analysis is used to evaluate variance.
9. *Labor*—1975 midwestern operating labor rates are projected. Sensitivity analysis is used to evaluate overall operating labor cost variance. Operating labor is escalated over the life of the project for only a few special cases to show effect.
10. *Utilities*—Recent energy cost escalation is recognized and 1975 values are projected (59). Values used in operating cost estimates for utilities supplied by power plant cover all costs for generation including return on investment, depreciation, and income taxes.
11. *Maintenance*—Various levels are analyzed by sensitivity analysis.
12. *Capital charges*—Regulated (profit and taxes included) economic basis is used. Annual operating cost estimates utilize a base value of 14.9% of fixed investment (10% cost of money). Level is varied by sensitivity analysis.
13. *On-stream time*—Annual operating costs are projected for operating times of 7,000, 5,000, 3,500, and 1,500 hr/yr. Later, these values are used to project a lifetime cost over a predefined 30-year declining operating schedule.
14. *Solids disposal*—Both on-site ponding and off-site disposal costs are evaluated for limestone and lime processes. On-site ponding includes prorated costs for calcium solids to cover pumping and piping to and from the pond, plus the 40-foot-deep, clay-lined pond. Off-site disposal includes proration of a thickener, filter, piping, pumps, cake conveyors, and loader at the power unit. Off-site charges are levied on a fee per ton of wet solids basis assumed to cover all contractor expenses for hauling, treatment, and final disposal. Sensitivity analysis is used to evaluate variance.
15. *Net sales revenue*—Base values–\$8/ton 100% H_2SO_4 as 98% H_2SO_4, \$6/ton 100% H_2SO_4 as 80% H_2SO_4, \$25/short ton for sulfur, \$20/ton for sodium sulfate are used. Variances are covered by sensitivity analysis.

Other important design and cost assumptions defined for consistent evaluation are:

1. Fly ash disposal facilities (ponds, pipes, pumps) are not included. Water balance is based on closed-loop operation.
2. System design assumed not "first of kind"; no redundancy is included, only pumps are spared; experienced design and construction team is assumed utilized.
3. Stack gas reheated to 175°F except Cat-Ox process.
4. Product storage–30 days except for Na_2SO_4–7 days.
5. Equipment, material, and construction labor shortages with accompanying overtime pay incentive not considered.

PRESENTATION OF RESULTS

For each of the five processes evaluated, a base case (500-MW, 3.5% S in coal, new unit) incorporating recognized technology is established and 16 cases including variations in power unit size, fuel type (coal vs. oil), sulfur in fuel, unit status (new vs. existing), sludge solids disposal method (off-site vs. on-site ponding) and SO_2 removal (80% vs. 90%) are projected. Sensitivity analyses are used to study other variations such as energy costs, raw material costs, maintenance costs, cost of capital, net sales revenue, and operating labor cost escalation. Several methods are used to present the results. For investment data, the following types of displays are presented for each process:

Total capital investment–tabulation of total investments presented for each case (tables 27-31).

Case variations–area investment summaries presented for each of the 16 case variations (see tables in Appendix B).

Equipment list, cost, size-scale factor, and data source–presented for base case (new 500-MW coal-fired unit burning coal with 3.5% S) (tables 46-50).

Summarized process area equipment and installation cost breakdown presented for base case and existing 500-MW system (tables 35-44).

For annual operating costs covering 7,000 hr/yr operation, three types of displays are used for each process.

Total average annual operating cost tabulation of total annual operating costs presented for each case (tables 51-55).

Case variations operating cost summaries presented for each of the 16 case variations (see tables in Appendix B).

Summarized effect of individual process areas on total costs presented for base case and existing 500-MW case (tables 59-68).

The lifetime operating costs are based on a prescribed 30-year operating profile 7,000 hours the first 10 years; 5,000 hours the next 5 years; 3,500 hours the next 5 years; 1,500 hours the last 10 years; average for 30 years 4,250 hr/yr. Two types of displays are used.

Net increase (decrease) in cost of power tabulation of total lifetime operating costs presented for all cases, actual and discounted (tables 70-74).

Case variations computer profiles of lifetime operating costs presented for each of the 16 case variations (see tables in Appendix B).

Capital Investment

A summary of the total capital investment requirements for the 16 case variations of all five processes is presented in table S-2. The relative ranking of the processes for new 3.5% S in coal-fired units (base case) in order of increasing investment is as follows:

1. Lime slurry
2. Limestone slurry
3. Magnesia slurry - regeneration
4. Sodium solution - SO_2 reduction
5. Catalytic oxidation

In comparing these rankings, it should be pointed out that the lime slurry process does not provide facilities for calcining limestone, and includes a minimum of facilities for storage of the calcined material.

A similar comparison for existing 3.5% S coal-fired power units which already meet particulate emission regulations shows the following process rankings:

Table S-2. Summary–Total Capital Investment Requirements[a,c]

Case	Years	Limestone process		Lime process		Magnesia process		Sodium process		Cat-Ox process[b]	
Coal-fired power unit	life	$	$/kW	$	$/kW	$	$/kW	$	$/kW	$	$/kW
90% SO_2 removal; on-site solids disposal											
200 MW N 3.5% S	30	13,031,000	65.2	11,749,000	58.7	14,139,000	70.7	16,198,000	81.0	19,537,000	97.7
200 MW E 3.5% S	20	11,344,000	56.7	13,036,000	65.2	14,372,000	71.9	17,149,000	85.7	17,735,000	88.7
500 MW E 3.5% S	25	23,088,000	46.2	26,027,000	52.1	26,026,000	52.1	31,208,000	62.4	37,907,000	75.8
500 MW N 2.0% S	30	22,600,000	45.2	20,232,000	40.5	22,958,000	45.9	26,706,000	53.4	42,520,000	85.0
500 MW N 3.5% S	30	25,163,000	50.3	22,422,000	44.8	26,406,000	52.8	30,491,000	61.0	42,736,000	85.5
500 MW N 5.0% S	30	27,343,000	54.7	24,272,000	48.5	29,355,000	58.7	33,709,000	67.4	42,928,000	85.9
1,000 MW E 3.5% S	25	35,133,000	35.1	38,133,000	38.1	38,717,000	38.7	47,721,000	47.7	62,913,000	62.9
1,000 MW N 3.5% S	30	37,725,000	37.7	32,765,000	32.8	38,865,000	38.9	45,832,000	45.8	69,889,000	69.9
80% SO_2 removal; on-site solids disposal											
500 MW N 3.5% S	30	24,267,000	48.5	21,586,000	43.2	25,568,000	51.1	29,127,000	58.3	–	–
90% SO_2 removal; off-site solids disposal											
500 MW N 3.5% S	30	20,532,000	41.1	18,323,000	36.6	–	–	–	–	–	–
90% SO_2 removal; on-site solids disposal (existing unit without existing particulate collection facilities)											
500 MW E 3.5% S	25	29,996,000	60.0	26,090,000	52.2	32,213,000	64.4	37,957,000	75.9	43,816,000	87.6
Oil-fired power unit											
90% SO_2 removal, on-site solids disposal											
200 MW N 2.5% S	30	8,263,000	41.3	9,482,000	47.4	8,861,000	44.3	10,324,000	51.6	13,069,000	65.3
500 MW N 1.0% S	30	12,935,000	25.9	15,961,000	31.9	12,695,000	25.4	15,198,000	30.4	28,067,000	56.1
500 MW N 2.5% S	30	15,473,000	30.9	18,148,000	36.3	16,080,000	32.2	18,949,000	37.9	28,277,000	56.6
500 MW N 4.0% S	30	17,481,000	35.0	19,861,000	39.7	18,765,000	37.5	21,893,000	43.8	28,449,000	56.9
500 MW E 2.5% S	25	18,657,000	37.3	21,817,000	43.6	20,376,000	40.8	24,445,000	48.9	32,824,000	65.6
1,000 MW N 2.5% S	30	23,384,000	23.4	26,341,000	26.3	23,656,000	23.7	28,765,000	28.8	46,356,000	46.4

[a] Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974. Minimum in process storage; only pumps are spared. Investment requirements for disposal of fly ash excluded. Construction labor shortages with accompanying overtime pay incentive not considered.

[b] All Cat-Ox installations require particulate removal to 0.005 gr/scf prior to entering converter. Because existing units are assumed to already meet EPA standards (0.1 lb particulate/MM Btu of heat input), only incremental additional precipitator is required.

[c] These investment costs depend heavily on project definition. For example, modifying the project scope of the limestone process as shown in table S-3 can increase the system cost for a new 500-MW, coal-fired unit from $50.3/kW to $113/kW.

1. Limestone slurry
2. Magnesia slurry - regeneration
3. Lime slurry
4. Sodium solution - SO_2 reduction
5. Catalytic oxidation

Table S-3. Limestone Slurry Process Investment with Modified Project Scope

	Investment $/kW
Base investment—limestone slurry process (including fly ash removal but not disposal)	
500-MW new coal-fired unit burning coal with 3.5% S, 12% ash, 90% SO_2 removal, 30-year life, 127,500 hours operation, on-site solids disposal, proven system, only pumps spared, no bypass ducts, experienced design and construction team, no overtime, 3-year program, 5% per year escalation, mid-1974 cost basis for scaling	50.30
Overtime to accelerate project or cover local demand requirements (50% of construction labor requirements)	3.20
Research and development costs for first of a kind process technology (as allowed by FPC accounting practice)	5.00
Power generation capital for lost capacity (normally covered by appropriate operating costs for power used in process)	4.50
Reliability provisions with added redundancy of scrubbers, other equipment, ducts and dampers, instrumentation for changeover (assumes no permission to run power plant without meeting SO_2 removal emission standards at all times)	6.00
Additional bypass ducts and dampers	2.00
Retrofit difficulty—moderate, space available beyond stack, less than three shutdowns required for tie-ins, field fabrication feasible	10.00
Fly ash pond including closed-loop provisions	5.50
500-ft stack added to project cost	6.00
Air quality monitoring system, 2-15 mile radius, 10 stations	0.70
Cost escalation of 10%/year instead of 5%	4.80
Possible delay of up to 2 years in equipment and material deliveries (1977 completion instead of 1975)	15.00
Total	113.00

The change in relative position of the lime slurry process ranking for existing units is a direct result of the assumption that two venturi scrubbers in series per gas train are required in the lime slurry process for removal of SO_2 from the gas, with or without the presence of fly ash. For each of the other aqueous scrubbing processes, existing units already meeting particulate emission regulations require only one scrubber per gas train. A savings would result for the lime slurry process for both new and existing applications and for the limestone slurry process for new units if a single scrubber capable of removing both particulate and SO_2 is available. In a separate TVA comparison of scrubber alternatives for the lime slurry process not included in this report, costs for a two-stage venturi lime system and a venturi-mobile bed lime system on a new coal-fired unit are shown to be reasonably close. However, for an existing coal-fired power plant, the mobile bed scrubber option requires about 22% less capital and 14% less operating cost than the venturi-venturi scheme. For similar reasons as given above, the process investment rankings for oil-fired units are the same as those for existing coal-fired units.

Another important result derived by comparing the investment projections in this study is the relatively minor investment savings realized (3.2%-4.5%) in designing for 80% SO_2 removal as compared to 90%.

The projected investments for limestone and lime slurry processes designed for off-site solids disposal represent savings equivalent to approximately 18% of the comparable projected on-site investment case. However, these projections do not include the capital for off-site waste treatment facilities which may be required; the contract fee ($4/ton of wet solids) for off-site disposal is assumed to include the necessary capital charges.

Accuracy—In reviewing the capital investment estimates for the five processes, it must be understood that the base case process definitions and estimates represent a proven system with a generalized investment. As an indication of how the project scope and corresponding investment could vary, the effect of "add ons" to the limestone slurry process base case estimate is shown in table S-3. Such "add ons" as delays in equipment delivery, physical space limitations, additional redundancy requirements, taller stacks, inclusion of a closed-loop fly ash disposal pond, and overtime to accelerate the project completion schedule could more than double the investment for the limestone slurry process.

Excluding these additional costs, but considering only the data available for this appraisal, the depth of investigation, and the reliability of the cost data, the projected overall investment accuracy for each of the processes is given in table S-4.

Annual Operating Cost

Table S-5 presents a summary of the total average annual operating costs for the 16 case variations of all five processes excluding credit for any byproducts produced. Corresponding to new 3.5% S coal-fired units, the relative ranking of average annual operating costs for the processes (base case) is as follows:

1. Limestone slurry
2. Lime slurry
3. Catalytic oxidation
4. Magnesia slurry - regeneration
5. Sodium solution - SO_2 reduction

Some important effects are not readily seen in comparing the ranking of processes for only one plant size and sulfur level. As determined in this study, the relative ranking of operating costs of the various processes is sensitive to changes in the assumed sulfur content of the fuel. As an illustration, a 500-MW, 1% S oil-fired power unit using the catalytic oxidation process has the third highest ranking operating cost of the five processes; but for fuel oils with sulfur contents greater than 4.0%, this process is the lowest in rank. As the results suggest, the catalytic oxidation process might show the greatest promise for small units burning high-sulfur oil. Although the sodium process is not the lowest ranking process for any of the cases presented in this study, it becomes more competitive in ranking for low-sulfur fuel oil-fired units. At the expense of small additional investment, its operating cost could be lowered by designing the process with multiple-effect evaporators thereby reducing the overall energy requirements about 18%.

The relative ranking of operating costs for existing 3.5% S coal-fired power units which already meet particulate emission regulations is shown below; however, it should be noted that magnesia and lime scrubbing costs are essentially the same.

1. Limestone slurry
2. (Magnesia slurry - regeneration
   (Lime slurry
3. Catalytic oxidation
4. Sodium solution - SO_2 reduction

In all of the projected annual operating cost estimates, capital charges are the most significant components followed by maintenance, energy, and raw material costs in varying orders of importance. For the magnesia and sodium processes which require thermal energy for regeneration of absorbent, steam or fuel oil are the second most significant components. Lime cost (which requires thermal energy in preparation) is the second most predominant item for the lime slurry process, whereas maintenance is second in predominance for the limestone slurry and catalytic oxidation processes.

Table S-4. Projected Overall Investment Estimate Accuracy Based on Available Data and Depth of Investigation

Process	Percent range
Limestone slurry	+20 to -5
Lime slurry	+20 to -10
Magnesia slurry - regeneration	+25 to -15
Sodium solution - regeneration	+25 to -10
Catalytic oxidation (Cat-Ox)	+20 to -10

The effect on annual operating costs of designing for 80% SO_2 removal as compared to 90% is relatively small. Operating cost savings range from 3.6% to 4.2% of the projected operating costs at 90% removal for the limestone and lime slurry processes.

Although investment costs for off-site disposal of solids in the limestone and lime slurry processes are projected to be less than for on-site disposal, the total operating costs for off-site disposal cases corresponding to a cost of \$4/ton of wet solids are 6.2% to 8.0% greater than the comparable on-site disposal cases.

The effect of excluding product credits from the annual operating cost estimates is illustrated in table S-6 which compares the projected annual operating costs for the five base case processes with the revenue from sale of byproducts.

Lifetime Operating Cost

Assumed credits for salable byproducts are reflected in the lifetime operating costs. Table S-7 presents a summary of the cumulative discounted process costs and equivalent levelized unit increase (decrease) in the cost of power over the life of the power unit for the five processes. Table S-8 shows the revenue assumed for each product and the actual and discounted cumulative credit for products which are included in the cumulative discounted process costs for the base case. With some exceptions, the relative ranking and trends in levelized unit operating costs are somewhat similar to those projected and discussed for annual operating costs. Lifetime levelized unit operating costs are slightly higher than corresponding average annual unit operating costs because of the declining operating profile of the power unit. The average on-stream time over the life of the plant is only 4,250 hr/yr, compared to the higher on-stream time of 7,000 hr/yr utilized for the annual operating cost estimates.

The limestone and lime slurry processes appear to show the most economic promise for new coal-fired power units at all unit sizes and sulfur levels considered in this study. For new oil-fired units utilizing low- and medium-sulfur oil, the limestone and magnesia processes show the most promise. However, the Cat-Ox process shows the most promise for high-sulfur oils. Because of credit for process heat, the levelized unit operating cost projected for the catalytic oxidation process declines with increasing sulfur

Table S-5. Summary – Total Average Annual Operating Costs^{a,b} (Excluding Credit for Byproducts)

Case		Limestone process		Lime process		Magnesia process		Sodium process		Cat-Ox process	
Coal-fired power unit	Years life	Total annual operating cost, $	Mills/ kWh	Total annual operating cost, $	Mills/ kWh	Total annual operating cost, $	Mills/ kWh	Total annual operating cost, $	Mills/ kWh	Total annual operating cost, $	Mills/ kWh
90% SO_2 removal; on-site solids disposal											
200 MW N 3.5% S	30	3,921,500	2.80	4,163,900	2.97	4,776,800	3.41	5,971,700	4.27	4,232,700	3.02
200 MW E 3.5% S	20	3,867,100	2.76	4,822,000	3.44	5,091,200	3.64	7,377,700	5.27	5,849,400	4.18
500 MW E 3.5% S	25	7,892,600	2.26	9,612,400	2.75	9,607,900	2.75	14,658,000	4.19	12,399,600	3.54
500 MW N 2.0% S	30	6,774,700	1.94	6,915,100	1.98	7,523,400	2.15	9,101,700	2.60	8,801,200	2.51
500 MW N 3.5% S	30	7,702,700	2.20	8,101,900	2.31	9,210,800	2.63	11,601,500	3.31	8,873,900	2.54
500 MW N 5.0% S	30	8,522,200	2.43	9,170,100	2.62	10,768,500	3.08	13,983,300	4.00	8,940,500	2.55
1,000 MW E 3.5% S	25	12,752,900	1.82	15,301,400	2.19	15,481,900	2.21	15,118,500	3.59	21,460,800	3.07
1,000 MW N 3.5% S	30	11,874,100	1.70	12,553,100	1.79	14,347,000	2.05	18,391,300	2.63	13,957,600	1.99
80% SO_2 removal; on-site solids disposal											
500 MW N 3.5% S	30	7,378,000	2.11	7,806,900	2.23	8,789,700	2.51	10,834,300	3.10	–	–
90% SO_2 removal; off-site solids disposal											
500 MW N 3.5% S	30	8,376,500	2.39	8,641,000	2.47	–	–	–	–	–	–
90% SO_2 removal (existing unit without existing particulate collection facilities)											
500 MW E 3.5% S	25	9,573,400	2.74	9,728,300	2.78	11,227,300	3.21	16,389,200	4.68	13,598,300	3.89
Oil-fired power unit											
90% SO_2 removal; on-site solids disposal											
200 MW N 2.5% S	30	2,842,000	2.03	3,413,500	2.44	3,204,400	2.29	4,269,200	3.05	2,750,100	1.96
500 MW N 1.0% S	30	4,732,500	1.35	5,748,600	1.64	4,633,100	1.32	5,854,700	1.67	5,743,600	1.64
500 MW N 2.5% S	30	5,564,400	1.59	6,852,800	1.96	6,092,700	1.74	8,305,100	2.37	5,677,500	1.62
500 MW N 4.0% S	30	6,281,800	1.79	7,742,300	2.21	7,393,500	2.11	10,640,500	3.04	5,565,100	1.59
500 MW E 2.5% S	25	6,587,300	1.88	8,001,500	2.29	7,308,700	2.09	10,261,600	2.93	11,126,100	3.18
1,000 MW N 2.5% S	30	8,987,400	1.28	10,795,200	1.54	9,715,900	1.39	13,686,200	1.96	8,911,900	1.27

[a] Power unit on-stream time, 7,000 hr/yr. Midwest plant location, 1975 operating costs. Investment and operating cost for disposal of fly ash excluded.

[b] These operating costs reflect capital investments shown in table S-2; they would increase if capital costs associated with additions to the scope such as shown in table S-3 were included.

Table S-6. Comparison of Projected Annual Operating Costs and Product Credits for Base Case Estimates at 7,000 Hours Annual Operation

Process	Total average annual operating cost, $	Annual credit for byproducts, $[a]	Net annual operating cost, $
Limestone	7,702,700	–	7,702,700
Lime	8,101,900	–	8,101,900
Magnesia	9,210,800	883,200	8,327,600
Sodium[b]	11,601,500	1,077,500	10,524,000
Cat-Ox	8,873,900	659,400	8,214,500

[a] Corresponds to credit of $8/ton 100% H_2SO_4 as 98% H_2SO_4 for magnesia slurry process; $25/short ton sulfur, $20/ton Na_2SO_4 for the sodium solution process; and $6/ton 100% H_2SO_4 as 80% H_2SO_4 for the Cat-Ox process.

[b] Corresponds to process utilizing a single-effect evaporator for regeneration of SO_2. The effect of using a double-effect evaporator on overall steam and energy requirements and total annual operating costs are discussed on page 133.

content of the fuel for both coal- and oil-fired units. In comparison with the projected annual operating costs, the relative higher costs on a lifetime basis which considers credit from sale of acid, indicate the strong influence of the declining operating profile assumed for the life of the plant and capital charges which are highest for the catalytic oxidation process.

CONCLUSIONS

The relative ranking of processes according to investment and operating costs varies with power unit size, fuel type, sulfur content of fuel, and plant status, with no single process being the most favorable for all of the cases considered in this study. Naturally, the particular premises used to set up the comparisons have an effect on the results. Under the premises selected the lime process has the lowest investment for new coal-fired power units; except for low (1.0%) sulfur oil-fired applications for which the magnesia process investment is lowest, the limestone process has the lowest investment for the other oil-fired units. In addition, there is some shifting of process ranking when the effect of sulfur content of fuel is evaluated. However, the investment for the Cat-Ox process is the highest of the five systems in all cases.

The relative ranking of processes based on annual operating costs indicates that the limestone process is lowest for all coal-fired units, but, process rankings for oil-fired units change with variations in sulfur content of the fuel. For the new 500-MW oil-fired plants, the magnesia process has the lowest annual operating cost for 1.0% S fuel oil, and the Cat-Ox process has the lowest cost for units burning 4.0% S oil. In between these sulfur levels, however, the limestone process is the most favorable. For most of the case variations, sodium scrubbing has the highest operating cost.

Capital charges are the largest component of operating costs for all processes. Although energy costs are also noticeable for all processes, they are the most significant for the sodium and magnesia processes which require thermal energy for regeneration of absorbent. Multiple-effect evaporation would reduce sodium scrubbing energy costs about 18%. Energy costs are more significant for oil-fired than for coal-fired installations because of the higher equivalent price of fuel. For all processes, labor cost is a minor component; Cat-Ox has both the lowest labor and energy costs.

Inclusion of product revenue in the base case lifetime operating cost estimates for the magnesia scrubbing, sodium scrubbing, and the catalytic oxidation process reduces the total lifetime operating costs only about 5% to 7%.

The cumulative effect of operating the various processes (base case) over the life of the power unit is equivalent to discounted unit cost increases ranging from $7.63 to $10.14 per ton of coal burned in comparison with a coal purchase price of $13.00 per ton projected for this study. Other cases vary from as low as $6.03 per ton of coal to as high as $19.96 per ton of coal burned. Generally, the cost of power to consumers could be expected to increase about 10% to 30% for stack gas scrubbing depending on scale of application, characteristics of each electrical power generation and transmission system and inflationary trends. For all case variations examined in this study, projected 1975 stack gas scrubbing operating costs range from 1.57 to 7.90 mills/kWh.

Table S-7. Summary – Cumulative Discounted Process Costs and Equivalent Levelized Unit Increase (Decrease) in Cost of Power Over the Life of the Power Unit[a] (Including Credit for Byproducts)

Case	Years life	Limestone process		Lime process		Magnesia process		Sodium process		Cat-Ox process	
		Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]	Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]	Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]	Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]	Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]
Coal-fired power unit											
90% SO_2 removal; on-site solids disposal											
200 MW N 3.5% S	30	40,142,800	3.66	41,112,500	3.75	44,860,300	4.09	55,045 000	5.02	44,823,500	4.08
200 MW E 3.5% S	20	29,067,800	4.73	34,979,000	5.69	36,106,200	5.87	48,568,300	7.90	42,423,000	6.90
500 MW E 3.5% S	25	70,550,000	3.09	84,117,600	3.69	78,292,200	3.43	113,985,500	5.00	106,607,800	4.67
500 MW N 2.0% S	30	69,314,200	2.53	68,709,000	2.50	71,503,600	2.61	85,604,900	3.12	95,780,300	3.49
500 MW N 3.5% S	30	78,439,900	2.86	79,593,300	2.90	84,249,500	3.07	104,292,300	3.80	94,320,900	3.44
500 MW N 5.0% S	30	86,426,800	3.15	89,293,900	3.25	95,621,900	3.49	121,660,300	4.43	92,805,300	3.38
1,000 MW E 3.5% S	25	111,985,400	2.45	130,977,300	2.87	121,156,200	2.66	188,464 400	4.13	181,013,700	3.97
1,000 MW N 3.5% S	30	120,015,500	2.19	121,789,900	2.22	126,808,00	2.31	160,375,200	2.92	148,117,600	2.70
80% SO_2 removal; on-site solids disposal											
500 MW N 3.5% S	30	75,259,300	2.74	76,687,900	2.80	81,119,800	2.96	98,245,000	3.58	–	–
90% SO_2 removal; off-site solids disposal											
500 MW N 3.5% S	30	80,426,200	2.93	80,903,300	2.95	–	–	–	–	–	–
90% SO_2 removal (existing unit without existing particulate collection facilities)											
500 MW E 3.5% S	25	87,143,300	3.82	84,924,200	3.72	93,875,800	4.12	130,713,900	5.73	119,124,800	5.22
Oil-fired power unit											
90% SO_2 removal; on-site solids disposal											
200 MW N 2.5% S	30	28,281,000	2.58	33,612,500	3.06	30,089,900	2.74	39,147,900	3.57	29,653,800	2.70
500 MW N 1.0% S	30	46,404,800	1.69	56,505,800	2.06	44,030,300	1.61	55,025,400	2.01	63,574,000	2.32
500 MW N 2.5% S	30	54,743,900	2.00	66,727,200	2.43	55,673,400	2.03	74,204,600	2.70	61,591,500	2.25
500 MW N 4.0% S	30	61,808,400	2.25	74,929,500	2.73	65,572,800	2.39	91,887,900	3.35	59,249,500	2.16
500 MW E 2.5% S	25	58,358,800	2.56	70,126,200	3.07	61,393,300	2.69	82,852,700	3.63	96,305,200	4.22
1,000 MW N 2.5% S	30	87,171,700	1.59	103,411,900	1.88	85,962,400	1.57	118,705,700	2.16	96,899,300	1.77

[a] Basis:

Over previously defined power unit operating profile. 30-yr life; 7,000 hr – 10 yr, 5,000 hr – 5 yr, 3,500 hr – 5 yr, 1,500 hr – 10 yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.
Constant labor cost assumed over life of project.

[b] Discounted at 10% to initial year.

[c] Equivalent to discounted process cost over life of power unit.

Table S-8. Lifetime Byproduct Production and Credit
Base Case, 500-MW New, Coal-Fired, 3.5% S, 30 Years Remaining Life

Process	Equivalent lifetime production		Net revenue	Cumulative revenue	
	Product	Short tons	\$/short ton	Actual \$	Discounted \$
Magnesia slurry - regeneration	100% H_2SO_4[a]	2,011,500	8.00	16,092,000	6,923,300
Sodium solution - SO_2 reduction	Sulfur	595,000	25.00	19,627,500	8,446,300
	Na_2SO_4	237,000	20.00		
Catalytic oxidation	100% H_2SO_4[b]	2,002,500	6.00	12,015,000	5,168,900

[a] As 98% H_2SO_4.

[b] As 80% H_2SO_4.

Introduction

For the past several years, the increasing emission of air pollutants to the environment from a multitude of sources has prompted industry and government on all levels to seek ways to reduce and control their discharge. Supported by funds provided by Congress in the Air Quality Act of 1967, the Clean Air Act of 1970, and subsequent appropriations, investigations have been directed toward determining the sources, causes, and effects of air pollution in the United States and considerable effort has been expended to research and develop methods of air pollution control.

One emission source receiving heavy attention is the large, stationary power plant burning fossil fuel. The primary pollutants emitted from these plants are particulates, sulfur dioxide, and nitrogen oxides. A typical 500-MW unit burning coal containing 3.5% S and 12% ash would, without any pollution controls, release each day up to 273 tons of SO_2, 405 tons of particulates, and 53 tons of nitrogen oxides. With the promulgation of the new-source emission standards for large steam generators by the Federal Environmental Protection Agency (10), the need for workable, reliable pollution control techniques has become critical to the future of fossil fuel power generation.

Of the three primary pollutants, control methods for SO_2 have commanded the greatest research and development interest for several years. Methods for particulate control such as stack gas electrostatic precipitators are considered to be commercial and reasonably reliable by the utility industry. Currently, effective techniques for nitrogen oxide control have narrowed to boiler design and flame temperature modifications. In contrast, SO_2 control investigations are being directed at both the front and the rear of a boiler-operating train including such concepts as fuels desulfurization, fuels gasification with sulfur removal, and wet or dry stack gas cleanup systems.

Probably the most advanced of these concepts are the stack gas SO_2 removal systems. Over the last few years, no less than 50 different processes have received attention and at least 5 have advanced from the pilot-plant stage to demonstration-scale installations.

Through the cooperative efforts of EPA, process developers, and several interested utilities, large-scale test programs are now under way for limestone scrubbing and lime scrubbing processes, both of which produce sludge for discard, and magnesia scrubbing - regeneration, catalytic oxidation, and sodium scrubbing - SO_2 reduction processes which produce recovered sulfuric acid or sulfur. The test and demonstration systems with their sponsors, size, location, and startup dates are shown in table 1.

EPA is providing a large part or all of the funding for these particular installations. In addition to these, several other full-scale SO_2 removal systems are being operated,

Table 1. EPA-Sponsored Stack Gas Desulfurization Demonstration Systems

EPA-sponsored process (byproduct)	Cooperating utility	Process developer	Location	Unit size and type	Expected startup
Limestone slurry scrubbing (sludge)	TVA	Bechtel and others	Shawnee Unit 10 Paducah, Ky.	10 MW coal	Under way
Lime slurry scrubbing (sludge)	TVA	Chemico, Bechtel, and others	Shawnee Unit 10 Paducah, Ky.	10 MW coal	Under way
Magnesia slurry scrubbing - regeneration (98% sulfuric acid)	Boston Edison	Chemico-Basic	Mystic Station 6 Boston, Mass.	155 MW oil	Completed
Catalytic oxidation (reheat) (80% sulfuric acid)	Illinois Power	Monsanto	Wood River Station 4 East Alton, Ill.	110 MW coal	Mid-1974
Sodium scrubbing - regeneration (sulfur)	Northern Indiana Public Service Co.	Davy Powergas Allied Chemical	D. H. Mitchell Station 11 Gary, Ind.	115 MW coal	Late 1975

constructed, or planned by a number of utilities at their own expense; a list is given in Appendix C (11).

At this time, probably the two questions uppermost in the minds of the utility industry regarding stack gas SO_2 removal processes are system reliability and cost. Reliability will slowly emerge as the equipment, materials of construction, and operation of each process show improved performance. As necessary, spare capacity may be specified for the more rigorous duties and provisions for interruptible service may need to be established.

Like reliability, accurate costs for SO_2 removal systems will emerge over a period of time; however, for decision purposes, detailed, comparative estimates are needed today to guide management's financial planning. Furthermore, the expected impact of pollution control on the cost of power to consumers is always on the minds of utility managers.

Unfortunately, like most new concepts emerging from research and development, SO_2 removal systems have a history of increasing costs as more is learned and better process definition is established. Cost estimates of the late 1960's were considerably lower than recent projections due to the early optimistic view of the investigators that the system unknowns would probably offset one another, simplified designs would prevail, and inexpensive materials of construction could be utilized. In most cases, these estimates could not be compared and were confusing because different systems, premises, and data sources were involved. Early capital estimates for stack gas scrubbing systems were as low as \$5.00/kW of power unit capacity and as high as \$40.00-\$50.00/kW (25, 37, 56, 57, 60) and initial operating cost estimates indicated a range of \$0.75 to \$1.50/ton of coal burned (0.25-0.80 mills/kWh). As time passed and pilot-plant results became known, the magnitude of the estimates increased (7, 26, 28, 40, 43), and as we know now, much higher costs can be expected.

The technologies associated with the five leading processes have advanced to the demonstration stage and large-scale systems are being offered for sale. Installations are being designed and constructed, and equipment and materials purchased; therefore, it is felt that more accurate cost estimates can be prepared.

The objective of this study was to prepare detailed, comparable estimates of capital and operating cost for the five most advanced SO_2 removal systems on a common, uniform basis and to display the results in a highly visible manner. The latest available process and equipment development, design, and economic data were used. The estimates are generally applicable to most power units in the United States with a specific base case to represent each process. The effect of all important design and economic variables was determined by the use of sensitivity analysis. The evaluation of each process includes a flow diagram, material balance, recommended equipment lists and layouts, and detailed capital investment and operating cost estimates for the base case, plus summarized estimates for each variation from the base case. Key variations cover unit size, fuel type, sulfur in fuel, plant status (new vs. existing), on-stream time, energy cost, maintenance cost, labor cost escalation, raw material cost, capital charges, and percent SO_2 removal. For the throwaway processes, off-site versus on-site solids disposal costs are evaluated and for recovery processes, sensitivity to net revenue changes is projected. Using the evaluation techniques established in a series of process conceptual design reports previously prepared by TVA for EPA (28, 56, 57), the best applications of each process are shown.

Process Background

Although the majority of research and development, design, and construction effort on the five systems evaluated in this study has occurred during the past 5 to 10 years, some of the basic work was performed as early as the 1930's. Much of this is still applicable and has been used to guide researchers of today. For perspective, a brief discussion of the process chemistry, history, and characteristics for these five processes is given here.

LIMESTONE-LIME SLURRY SCRUBBING

Of all the stack gas SO_2 removal systems, limestone and lime slurry processes have received the most attention. During recent years, scientists and engineers have examined the chemistry of the systems, carried out bench-scale and pilot-plant studies, prepared various designs for full-scale demonstrations, and in some cases, operated these for limited periods.

In regard to the chemistry, there is some agreement for the following series of reactions occurring during SO_2 absorption by an aqueous scrubbing liquor.

$$SO_2\ (g) \rightleftharpoons SO_2\ (aq) \tag{1}$$
$$SO_2\ (aq) + H_2O \rightleftharpoons H_2SO_3 \rightleftharpoons HSO_3^- + H^+ \tag{2}$$
$$HSO_3^- \rightleftharpoons H^+ + SO_3^= \tag{3}$$

When using limestone, it simultaneously dissolves into the scrubbing liquor as shown in equations 4 and 5.

$$CaCO_3\ (s) \rightleftharpoons CaCO_3\ (aq) \tag{4}$$
$$CaCO_3\ (aq) \rightleftharpoons Ca^{++} + CO_3^= \tag{5}$$

Sulfite ion combines with calcium to yield the very insoluble calcium sulfite hemihydrate.

$$Ca^{++} + SO_3^= + \tfrac{1}{2}H_2O \rightleftharpoons CaSO_3 \cdot \tfrac{1}{2}H_2O \downarrow \tag{6}$$

Carbon dioxide, either in the flue gas or from calcium carbonate interacts with water as shown in equations 7 and 8.

$$CO_2\ (g) + H_2O \rightleftharpoons H_2CO_3\ (aq) \rightleftharpoons H^+ + HCO_3^- \tag{7}$$
$$HCO_3^- \rightleftharpoons H^+ + CO_3^= \tag{8}$$

In addition, sulfite ion may be ultimately converted to gypsum via the following reactions:

$$SO_3^= + \tfrac{1}{2}O_2 \rightarrow SO_4^= \tag{9}$$
$$Ca^{++} + SO_4^= + 2H_2O \rightleftharpoons CaSO_4 \cdot 2H_2O\ (s) \downarrow \tag{10}$$

When lime is substituted for limestone as the scrubbing agent, the additional reactions shown below also occur.

$$CaO + H_2O \rightarrow Ca(OH)_2\ (s) \tag{11}$$
$$Ca(OH)_2\ (s) \rightleftharpoons Ca(OH)_2\ (aq) \tag{12}$$
$$Ca(OH)_2\ (aq) \rightleftharpoons Ca^{++} + 2OH^- \tag{13}$$
$$Ca(OH)_2\ (aq) + CO_3^= \rightleftharpoons CaCO_3\ (aq) + 2OH^- \tag{14}$$
$$H^+ + OH^- \rightleftharpoons H_2O \tag{15}$$

The pH of lime slurries is higher than that of limestone slurries because of the additional hydroxide ion supplied by the slaked lime. The first use of limestone, lime, or their related compounds in an aqueous medium as an absorbent for SO_2 was over 40 years ago at the Battersea and Bankside power stations in London (21, 42). A once-through system was utilized. About the same time (early 1930's), the Imperial Chemical Industries-James Howden and Company, Ltd. (32), tried a circulating liquor system using lime or chalk at the Tir John (Swansea) and Fulham (London) power stations. This 35- to 40-MW system was the first effort to develop a closed-loop (water) process. The Tir John installation was abandoned early, however, the Fulham unit operated until World War II when it was shut down because the plume was thought to be attracting enemy aircraft.

In the early 1950's, TVA (55) conducted some brief pilot-plant studies using a 10% limestone slurry in a packed tower.

In more recent times (1965), Wisconsin Electric Power and Universal Oil Products (UOP) carried out a 1-MW joint program (38) on a coal-fired 120-MW boiler using the "turbulent contact absorber" (TCA) (a scrubber filled with mobile plastic spheres). The device showed considerable promise by removing 85% of the SO_2 and 99% of the fly ash. Another program (1966-1967) was conducted by Combustion Engineering (CE) (37) and Detroit Edison in which limestone was injected into a boiler to get low-cost calcination and react the CaO with SO_2 in the gas. The reaction products were then caught in a downstream scrubber (National Dust Collector Hydro-Filter—a marble bed device). Results were encouraging with 98% SO_2 removal and 99.5% removal of the dust.

As interest in SO_2 removal systems escalated in the late 1960's, several other companies initiated research and development work on limestone and lime scrubbing processes. Such U.S. concerns as Babcock and Wilcox Company (B and W), Chemical Construction Corporation

(Chemico), Research-Cottrell, Zurn Industries, and Peabody Coal Company developed data for commercial systems using limestone scrubbing, and Chemico, Combustion Engineering (CE), and Combustion Equipment Associates (CEA) worked with lime scrubbing. In addition, EPA and TVA joined with Bechtel Corporation in an extensive research program on a TVA boiler at Shawnee Steam Plant (near Paducah, Kentucky). Outside the United States, AB Bahco Ventilation in Sweden, Gottfried Bischoff KG in Germany, Mitsubishi Heavy Industries in Japan, and NIIOGAZ (State Research Institute of Industrial and Sanitary Gas Cleaning) in the USSR have researched limestone-lime scrubbing.

On the basis of their early pilot work, CE built four scrubber systems in the period 1968-1972, all embodying boiler injection of limestone followed by scrubbing in marble-bed scrubbers.

Company	Station	Boiler size, MW	Number of scrubbers
Union Electric	Meramec	140	2
Kansas Power and Light	Lawrence	125	2
Kansas Power and Light	Lawrence	420	6
Kansas City Power and Light	Hawthorne	2 x 140	4

Notwithstanding the promising pilot-plant operation at Detroit Edison, all of the early full-scale units had major difficulties with corrosion, erosion, solids deposition (both "mud" deposits and scaling), and demister plugging. Solids deposition occurred not only in the scrubber but also in the boiler. Removal of SO_2 was not as high as in the pilot plant.

The Union Electric operation has been abandoned and one of the Hawthorne scrubbers has been converted to limestone slurry scrubbing. The other units are still being operated and some progress is being made in resolving the problems. However, it seems generally accepted now that injecting limestone into the boiler is not a good practice. CE has shifted emphasis to introduction of lime or limestone into the scrubber loop rather than into the boiler.

CE's latest effort was at Louisville Gas and Electric's Paddy's Run station (61), where two 35-MW marble-bed scrubbers were started up in April 1973. The absorbent, introduced into the pump tank in the scrubber loop, is byproduct lime (hydrated) from a nearby carbide operation. The system has operated efficiently and reliably for short periods since startup, and is generally regarded as one of the best applications of lime-scrubbing technology.

B and W concentrated on use of limestone, first carrying out a pilot-plant program in its own laboratories and later building a two-scrubber installation on a 160-MW boiler at Commonwealth Edison's Will County station near Chicago. One scrubber is of the TCA type described earlier and the other a perforated-plate type developed by B and W. The system, started up in February 1972, has been subject to continuing problems and is still not operating satisfactorily. In addition to problems in the scrubber and demister, Will County has had trouble with mist passing through the demister and corroding the steam-heated tube-type reheaters.

The La Cygne (Kansas) plant of Kansas City Power and Light, a single 800-MW boiler fitted with seven B and W scrubber trains, was started up in June 1973. Each train consists of a venturi scrubber for particulate removal followed by a perforated-plate scrubber for SO_2. Problems similar to those at Will County have been encountered.

Although they offer a limestone scrubbing process, Chemico has been more active in lime slurry scrubbing. In March 1972, a Chemico-designed two-train system (two venturis in series in each train) was started up on a 156-MW coal-fired power boiler at Mitsui Aluminum's Omuta plant in Japan (45). The absorbent is byproduct carbide lime, similar to that used at Louisville Gas and Electric as described earlier. Since the boiler is equipped with efficient electrostatic precipitators, little or no particulate removal is required in the scrubbers. Mitsui Aluminum has reported little difficulty in operation and the system apparently has operated reliably.

In the United States, Chemico has installed a 400-MW venturi system at Duquesne Light's Phillips station near Pittsburgh. There are four scrubber trains, each with a single venturi for particulate removal; one of the trains also has a second venturi in series to test SO_2 removal. The particulate scrubbers were started up in late 1973. The Phillips installation was to be a test of the Chemico process under conditions more analogous to the U.S. power industry than those in Japan.

Research-Cottrell, a major manufacturer of electrostatic precipitators, has developed a limestone-scrubbing system based on use of a scrubber packed with an open type of packing similar to that generally used in cooling towers. After an initial pilot-plant test program at an American Electric Power station in Ohio, Research-Cottrell built a two-train system on a 115-MW boiler at the Cholla station of Arizona Public Service in Arizona. The system was started up in late 1973.

One of the more extensive limestone-lime scrubbing programs is the joint EPA-Bechtel-TVA program started in 1970 (5). The EPA-funded test demonstration facility at TVA's Shawnee Steam Plant is probably the most versatile and sophisticated SO_2 prototype in the world. The test program is under the direction of Bechtel and the facility is operated by TVA. Three 10-MW scrubbers of different types are operated in parallel, each fully instrumented and feeding data into an advanced data processing system. All phases of lime-limestone scrubbing are being studied, from operating parameter optimization to equipment reliability.

Over $12 million has already been spent by EPA for work here.

In the planned program, emphasis will be placed on sludge disposal (41, 44), which is generally regarded as the main unresolved problem in lime-limestone scrubbing. Test ponds will be constructed to evaluate both waste pond disposal and methods for sludge "stabilization" (conversion to a nonleachable and structurally stable solid).

The process design data used in this study for limestone scrubbing are based primarily on the Shawnee (5) test work and those for lime scrubbing are based on Chemico technology (45). Chemico's assistance also included a review. In addition, available information from some of the other mentioned full-scale facilities influenced the designs.

MAGNESIA SLURRY SCRUBBING - REGENERATION

A detailed background of this process can be found in the EPA-TVA conceptual design report published during 1973 (28). Around the world, development work on the magnesia scrubbing process has followed at least three major technological routes since the early thirties. Russian, Japanese, and American developers have concentrated on the use of magnesium sulfite-magnesium oxide slurries having a basic pH; whereas, a German company, Grillo-Werke AG, has researched the use of an absorbent activator, manganese dioxide, with the slurry. In addition, using technology associated with sulfite paper pulping practice, at least one American company has also investigated the use of magnesium sulfites in acidic solution so that simultaneous particulate and SO_2 removal can be accomplished with a single scrubber in coal-fired unit application. The basic slurry process is the most advanced system and, therefore, is the one evaluated in this study.

There are three series of reactions which occur in the magnesia slurry scrubbing - regeneration process. In the first series, the scrubbing step, the following reactions predominate:

SO_2 absorption, represented by the reactions:

$$5H_2O + Mg(OH)_2 + SO_2 \rightarrow MgSO_3\cdot 6H_2O \downarrow \tag{16}$$

$$SO_2 + MgSO_3\cdot 6H_2O \rightarrow Mg(HSO_3)_2 + 5H_2O \tag{17}$$

Bisulfite neutralization, represented by the reaction:

$$Mg(HSO_3)_2 + MgO + 11\ H_2O \rightarrow 2MgSO_3\cdot 6H_2O \downarrow \tag{18}$$

Magnesium sulfite oxidation, represented by the reaction:

$$2MgSO_3 + O_2 \rightarrow 2MgSO_4 \tag{19}$$

Magnesium sulfite hexahydrate crystals are removed from the scrubbing system and either sent directly to a dryer or thermally converted to $MgSO_3\cdot 3H_2O$ and then dried. It is expected that some $MgSO_4\cdot 7H_2O$ and perhaps $MgSO_4\cdot 6H_2O$ will also be occluded in the $MgSO_3\cdot 6H_2O$. The chemical reactions which occur in the dryer are:

$$MgSO_3\cdot 3H_2O \xrightarrow{\Delta} MgSO_3 + 3H_2O \uparrow \tag{20}$$

or

$$MgSO_3\cdot 6H_2O \xrightarrow{\Delta} MgSO_3 + 6H_2O \uparrow \tag{21}$$

and

$$MgSO_4\cdot 7H_2O \xrightarrow{\Delta} MgSO_4 + 7H_2O \uparrow \tag{22}$$

The dry crystals are calcined at 800° to 1100°C in the presence of coke or a reducing atmosphere to regenerate MgO and SO_2. The reactions occurring in the calciner are:

$$MgSO_3 \rightarrow MgO + SO_2 \uparrow \tag{23}$$

$$C + 1/2O_2 \rightarrow CO \tag{24}$$

$$CO + MgSO_4 \rightarrow CO_2 + MgO + SO_2 \uparrow \tag{25}$$

The magnesium oxide is cycled back to the scrubber system and the SO_2 is sent to a sulfuric acid plant.

In the United States, development of the magnesia scrubbing - regeneration process for SO_2 control has been undertaken primarily by two companies—Chemico-Basic (a joint company formed by Chemical Construction Corporation, New York, and Basic Chemicals, Cleveland, Ohio) and Babcock and Wilcox Company, Barberton, Ohio. In addition, a contractor-constructor, United Engineers and Constructors, Philadelphia, is actively involved in design technology.

Chemico-Basic was the first U.S. company to market a complete magnesia scrubbing - regeneration process for sulfuric acid production using SO_2 from power plants, smelters, or sulfuric acid plant waste gases. Pilot-plant test work was completed at several locations, including particulate scrubbing at the Holtwood Station of Pennsylvania Power and Light; Crane Station of Baltimore Gas and Electric; and Dickerson Station of Potomac Electric Power; and SO_2 scrubbing at Canal Electric Company, Sandwich, Massachusetts; Olin Corporation (sulfuric acid plant) in Baltimore, Maryland; and Cleveland Electrical Illuminating Company in Cleveland, Ohio. Most of these pilot plants processed about 1,500 cfm of gas or 0.50-0.75-MW equivalent.

One of the more important contributions on magnesia slurry scrubbing is a study (8) completed in 1970 by B and W for the Office of Research and Monitoring of EPA. In a pilot plant (2,000 acfm) at the Alliance, Ohio, Research Center, data were obtained on both particulate and SO_2 scrubbing in a venturi-type scrubber and SO_2 removal in a mobile-bed scrubber (termed Floating Bed Absorber). Tests were made of the effect of liquid:gas ratio, pressure drop, slurry composition (including pH and sulfate concentration), stoichiometry, fly ash, preslaking of MgO, and scrubber liquid residence time on SO_2 removal. In addition, evaluations were made of the scaling problem, SO_2 formation in the coal burners, and NO_X removal. The particulate and SO_2 removal data derived in this study should be very useful in the design of power plant scrubber systems.

Because of the advanced development of the basic magnesia slurry process, it was selected by EPA as one of the more promising SO_2 control processes ready for demonstration in a commercial-size installation. In July 1970, EPA, an electric utility company (Boston Edison), and a design engineering firm (Chemico-Basic) combined as a group to fund, design, build, and operate the magnesia scrubbing system at Boston Edison's Mystic Station No. 6, a 155-MW steam generating unit located in Everett, Massachusetts. The station, an oil-fired facility, was equipped with a single-stage venturi scrubber system to remove SO_2 from the stack gases. The magnesium sulfite slurry formed is dewatered and dried and the crystals shipped to an existing sulfuric acid plant owned by Essex Chemical Corporation located at Runford, Rhode Island. There the material is calcined to release SO_2 for the 98% acid unit and the resultant magnesium oxide shipped back to the power plant.

During a 2-year test period beginning in 1972 (27), a program was undertaken to test various operating parameters, optimize emission control under a power plant operating cycle, demonstrate reliability, and accurately define system operating cost. At the end of the test and evaluation program, a report will be prepared presenting the results.

A second system utilizing magnesia slurry scrubbing has been installed by Potomac Electric Power Company at their Dickerson, Maryland, station, Unit No. 3. Half of the flue gas from a 195-MW coal-fired unit is treated by a two-stage venturi scrubber system to remove both particulates and SO_2. Particulate removal is expected to exceed 99%, and SO_2 removal will be 90% plus. Startup is under way. The magnesium sulfite from the SO_2 scrubber will be dewatered, dried, and then shipped to the Essex Chemical's sulfuric acid plant in Rhode Island for processing in the EPA unit associated with the Boston Edison project. Potomac Electric Power Company funded the scrubbing portion of the system which was designed by Chemico and constructed by Brown and Root.

A third installation of magnesia scrubbing is located at the Eddystone Station of Philadelphia Electric. The 120-MW coal-fired system, designed and built by United Engineers and Constructors (1), is scheduled for startup in late 1974.

For the most part, the process design of the magnesia scrubbing system evaluated in this study is based on the Boston Edison demonstration unit. Some incorporated modifications such as fluid bed drying and calcining remain to be proven in practice; however, in all cases, the alterations have been reviewed by Chemico.

SODIUM SOLUTION SCRUBBING - SO_2 REDUCTION TO SULFUR

Technology related to scrubbing SO_2 with soluble, inorganic sodium compounds also dates back to the Johnstone (24) work of the late 1920's and early 1930's. Even in the initial days of SO_2 removal research, the desirable qualities of high sodium absorbent solubility and low vapor pressures were recognized. Most of the early efforts utilized sodium carbonate or sodium hydroxide to form sulfite-bisulfite scrubbing solutions. One of the early drawbacks encountered was high sulfate formation (oxidation).

During recent years, the versatility of sodium solution scrubbing has received even more attention as process developers sought to use the system to produce either salable liquid SO_2, sulfuric acid, or elemental sulfur, or as the first step of a throwaway "double alkali" process. The apparently less troublesome scrubbing step has induced several developers to combine it with their proprietary downstream processing technology creating a variety of systems for sale.

Some of the organizations presently involved in the use of sodium scrubbing processes for stack gas SO_2 removal are Davy Powergas Inc., Lakeland, Florida; Combustion Equipment Associates, New York, New York; Universal Oil Products, Des Plaines, Illinois; Stone and Webster - Ionics, Boston, Massachusetts; and Envirotech Corporation, Lebanon, Pennsylvania. A list of full-scale systems from these developers is given in Appendix C. Other companies are combining the sodium ion with organics for SO_2 removal.

The system given treatment in this study is the Wellman-Lord scrubbing process (Davy Powergas) coupled with Allied Chemical (Morristown, New Jersey) technology for SO_2 reduction to elemental sulfur. Such a system is to undergo EPA-sponsored demonstration (47) at the D. H. Mitchell Station of the Northern Indiana Public Service Company (NIPSCO) near Gary, Indiana.

The principal chemical reactions involved are discussed below. The scrubbing step is primarily sodium sulfite conversion to sodium bisulfite.

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3 \qquad (26)$$

The bisulfite-rich absorbent is then thermally decomposed in an evaporator - crystallizer.

$$2NaHSO_3 \xrightarrow[\text{steam}]{\Delta} Na_2SO_3\ (\text{crystals})\downarrow + SO_2\uparrow + H_2O\uparrow \qquad (27)$$

At this point the concentrated SO_2 from the Wellman-Lord process is processed in the Allied Chemical reduction unit by a series of reactions. Half of the SO_2 is reduced by equation 28:

$$2SO_2 + CH_4 \rightarrow CO_2 + 2H_2O + 2S \qquad (28)$$

A major portion of the remaining SO_2 is converted as follows:

$$3SO_2 + 2CH_4 \rightarrow 2CO_2 + 2H_2O + 2H_2S + S \qquad (29)$$

The resulting H_2S is then reacted with SO_2:

$$2H_2S + SO_2 \rightarrow 2H_2O + 3S \qquad (30)$$

The Wellman-Lord process (62) was conceived in mid-1966, successfully demonstrated on a bench-scale operation, and proven to be feasible in late 1966. After early pilot-plant experience (35) on a Tampa Electric Company station and a Baltimore Gas and Electric Company unit in 1967-1969, modifications to the system were made and the first commercial unit was installed in July 1970 at the Paulsboro, New Jersey, sulfuric acid plant of the Olin Corporation. This early installation treated successfully about 45,000 scfm of acid plant tail gas. Since then, several systems have been installed and operated on a variety of offgas feeds in both the United States and Japan.

One of the early successes (52) was a unit attached to an oil-fired boiler at the Japan Synthetic Rubber Company plant near Chiba, Japan. This unit started up in August 1971 processing about 124,000 scfm (75 MW) of stack gas. Thus far, reliability has approached 95%-100% for 2 years of operation reducing SO_2 from 1,500 to 150 ppm. Another unit installed in 1973 on a 220-MW unit at the Chubu (Japan) Electric Power Company has been said to operate with load variations from 35% to 105%.

One of the initial problems encountered with the process was high oxidation of sulfite to sulfate which is a liability since disposal of sodium sulfate is difficult and makeup requirements would be expensive. It is too soluble to be dumped and the end use markets are not very large (glass, detergent, pulp, and paper processing). Recent development efforts, however, have led to the successful use of an inhibitor and process alterations which minimize this difficulty.

The Allied Chemical (22) phase of the process system is a recent proprietary development coming from smelter offgas control. In late 1970, Allied completed installation of a catalytic SO_2 reduction system at the Falconbridge Nickel Mines, Ltd., facility near Sudbury, Ontario, Canada.

The quantity of gas treated at Falconbridge (500 long tons/day of sulfur) was equivalent to flue gas from 2,000 MW of power generation when fired with 3% sulfur coal. The initial commercial installation was so large that most of the applications to power plants will require scaledown from this size rather than scaleup. This system operated for about 2 years before shutdown due to shortages in feed from the smelter.

The Allied reduction process currently uses natural gas as a source of methane; however, work is under way to alter the system to other more plentiful reductants. The process can handle SO_2 concentrations as low as 4% to 5% and as high as 100% where oxygen is limited. In those process gases where oxygen content is too high or SO_2 concentration is too low for direct application, the process may be joined with one of several regenerable flue gas scrubbing processes which recovers the SO_2 in a concentrated, low-oxygen gas stream. It is this procedure which will be used in the demonstration on the 115-MW coal-fired No. 11 unit at the NIPSCO D. H. Mitchell Station. This installation will be equally funded by EPA and NIPSCO and is expected to cost about $11 million to construct. It is the only EPA-sponsored system to produce elemental sulfur. Startup is expected by late 1975.

In the full-scale system, 420,000 acfm of stack gas at 288°F will be scrubbed in a multitray device with the effluent processed to yield about 4,230 lb/hr of 85% SO_2 gas for feed to the Allied Chemical reduction unit. Sulfur produced in the system (20 long tons per day) will be sold by Allied.

As with the other projects funded by EPA, the Mitchell demonstration will be studied to assess emission control capability, operating reliability, flexibility, and costs. A three-phase evaluation program is projected including (1) preliminary engineering and cost estimates provided by Davy Powergas in late 1972, (2) procurement of equipment, construction and startup by late 1975, and (3) a 1-year operation by Allied funded entirely by NIPSCO.

For the sodium scrubbing - SO_2 reduction process evaluation in this study, information supplied by Davy Powergas and Allied Chemical was used to prepare the process design and cost estimates. Most of this material is still considered proprietary and, therefore, cannot be released at this time; however, the evaluation is representative of the process and has been reviewed by the developers.

CATALYTIC OXIDATION

The catalytic oxidation process evaluated in this study is the proprietary Cat-Ox process developed by the Monsanto Company, St. Louis, Missouri. For many years, Monsanto has been a leader in technology for catalytic oxidation of SO_2 to SO_3 when burning sulfur for the manufacture of sulfuric acid. Their experience and expertise of this field were used as a starting point in the development of the Cat-Ox process which normally produces about 80% sulfuric acid. The primary chemical reactions of the process are:

$$2SO_2 + O_2 \xrightarrow[\text{catalyst}]{} 2SO_3 \qquad (31)$$

$$SO_3 + H_2O \rightarrow H_2SO_4 \qquad (32)$$

The SO_2 in the stack gas combines with oxygen and moisture already in the gas. The concentration of acid which can be made depends primarily on SO_2 concentration and the exit temperature of the stack gas to the atmosphere. Cooling the gas too low will dilute the resultant product by moisture condensation.

The process is best suited for installation on a new unit so that the original design can provide the high temperature (850°-900°F) needed to convert SO_2 to SO_3. Reheat of the gas is necessary if installation is on an existing unit.

Research on the process was started in 1961 as a joint project of Monsanto Company, Pennsylvania Electric Company, Air Preheater Company, and Research-Cottrell, Inc., at the Seward station of Pennsylvania Electric. Later, Monsanto assumed principal interest and with cooperation from Metropolitan Edison built a 15-MW prototype (50) at their Portland, Pennsylvania, station. This unit was completed and placed on-stream in the fall of 1967. Approximately 63,000 acfm of stack gas taken from the 250-MW No. 2 boiler at Portland was passed through the prototype.

Fly ash removal was particularly critical to protect the oxidation catalyst and the high-temperature, high-efficiency precipitator installed was found to be very effective for this service.

After about a year's operation, the project was pronounced successful in late 1968 and ready for sale to utilities; this process was the first to be ready for demonstration.

In 1970, EPA agreed to partly finance a full-scale demonstration of a reheat Cat-Ox system on an existing 110-MW coal-fired unit of Illinois Power at the Wood River Station near East Alton, Illinois. Illinois Power agreed to furnish \$3.8 million and EPA \$3.5 million for the project. Monsanto's Enviro-Chem Systems, Inc., provided the technology for the installation on No. 4 boiler.

The detailed engineering was started in November 1970 and on-site construction started January 1971. The unit was ready for operation by mid-1973; however, a limit on the natural gas supply for reheating the stack gas from 310° to 850°F required a delay for modification of the reheat burner system. System startup is now scheduled for September 1974. Final cost for the project is now expected to be \$8,150,000 or \$74/kW (31).

SO_2 conversion to SO_3 is expected to be 90% or better; however, leakage across seals of the heat exchangers allows about 5% of the gas to bypass the converter resulting in an overall system efficiency of about 85%. Due to the high-efficiency electrostatic precipitator, the screening effect of the converter bed, and the efficient absorbing tower and mist eliminator, particulate emission is virtually negligible.

An extended test program is planned by EPA for the demonstration unit. The Mitre Corporation (12) has been contracted to carry out the test and evaluation program.

For a period of 5 years, Monsanto Enviro-Chem will be responsible for disposal of the byproduct acid from the system. The revenues from the acid sales will be split 75% to Illinois Power and 25% to Monsanto. Approximately 19,000 tons/yr of 100% equivalent acid are expected to be produced.

The Cat-Ox system designs used in this study are based on Monsanto's design manual for the Wood River unit and have been reviewed by Monsanto.

Power Plant, Process Design, And Economic Premises

To compare the five stack gas desulfurization systems under uniform conditions, a set of specific design assumptions are presented to aid in flowsheet, equipment, and economic calculations. Criteria for each of the processes are presented to establish efficiencies, production rate, and other process design characteristics necessary to evaluate the five individual processes simultaneously. The economic premises are prepared with consideration of the many factors that can affect costs.

POWER PLANT

Historical FPC data (17) and TVA power plant experience serve as a basis for establishing values for such parameters as power unit size, unit heat rate, lifetime plant capacity schedule, boiler type, and remaining years of operation for existing units. Although the available data vary over a wide range, the values used are considered to be representative of the more typical modern boiler units less than 10 years old for which stack gas desulfurization systems would be considered.

Fuels

There are distinct and important differences between control systems for power units burning coal or oil; therefore, coverage includes both fuels with emphasis on coal because it is the fuel of greatest pollution potential. Fuel compositions vary considerably; however, as in previous conceptual design reports, the following representative (28) fuel characteristics are selected to evaluate the economics of SO_2 removal.

1. *Coal*—Although coals of relatively low sulfur and ash content and high heating value are the most desirable, a wide range of coals are currently being used; therefore, coals with sulfur contents of 2.0%, 3.5%, and 5.0%, total heating value of 12,000 Btu/lb, and ash content of 12% are considered.
2. *Oil*—Since sulfur content of fuel oil is generally less than for coal, concentrations of 1.0%, 2.5%, and 4.0% sulfur are assumed. A No. 6 fuel oil with an API gravity of 15° and an ash content of 0.1% is assumed to be a representative fuel with a total heating value of 18,500 Btu/lb or 140,000 Btu/gal for all sulfur levels (46).

Operation

The size of fossil-fueled power plants currently ranges up to 1,300 MW. Although a considerable portion of the future generating capacity will be from power units 500 MW or larger, many older and smaller units, 200 MW or less, will be utilized in years to come. To determine the effect of power plant size and status on the economics of SO_2 removal, three unit sizes, 200, 500, and 1,000 MW, are given detailed attention for both new and existing units. Power plant efficiencies vary with size and status. Representative heat rates used in this study are shown in table 2.

Based on power plant evaluation guidelines suggested by the FPC (14), the expected operating life of a new fossil-fueled power unit is about 30 years. Historically, the highest operating rates (on-stream time) occur during the first 10 years of operation and decline thereafter. Reflecting TVA experience (51), table 3 shows the power plant operating schedule assumed for this study. This schedule represents a total on-stream time of 127,500 hours over the life of the plant.

When considering SO_2 control processes for power plants, both the tendency of units to decline in utilization over their operating life and the load variation on a short-term basis because of electrical demand variation can be significant. For recovery processes in particular, the

Table 2. Power Unit Input Heat Requirements

Size, MW	Status	Heat rate, Btu/kWh
1,000	New	8,700
1,000	Existing	9,000
500	New	9,000
500	Existing	9,200
200	New	9,200
200	Existing	9,500

Table 3. Assumed Power Plant Capacity Schedule

Operating year	Capacity factor % (nameplate rating)	Annual kWh/kW capacity
1-10	80	7,000
11-15	57	5,000
16-20	40	3,500
21-30	17	1,500
Average for 30-year life	48.5	4,250

associated large investment requirements and market commitments usually make it desirable to operate the recovery system at a high capacity factor to minimize the effect of the continuing fixed capital charges on unit production costs.

Those recovery processes which sequentially absorb SO_2 and later regenerate the SO_2 for recovery of the absorbent (magnesia slurry - regeneration and sodium solution - SO_2 reduction processes) could be designed with supplemental storage facilities for the absorber effluent. This would allow the regeneration facilities to be designed for smaller throughput capacities resulting in a slight investment savings since they would be capable of regenerating the absorbent in storage when the power plant is operating at a reduced load. Because of the relatively high operating capacity (80%) assumed for the initial years of operation of the power plant, however, this method of design and operation is not utilized in the current study.

Since chemical plants are not normally designed to operate at capacities greater than 90%, the maximum amount of regeneration capacity which could be saved in comparison to the base operating capacity of the power plant is only 12.5%. For the sodium process this amounts to an investment savings of approximately 4% and an operating cost savings of 1.4%. The investment savings for this method of design would only be significant for existing power units with low anticipated load factors.

Since existing power units can be expected to have fewer remaining years of operation at high capacity factors, power plant age is also an important parameter. In this study, existing 200-MW units are assumed to be 10 years old, with a remaining life of 20 years, or 57,500 operating hours; and 500-MW and 1,000-MW units are assumed to be 5 years old, with a remaining life of 25 years, or 92,500 operating hours.

Design

To serve as a basis for flowsheet calculations, it is desirable to define distinct flue gas compositions for both coal- and oil-fired systems. In doing so, however, it should be recognized that these parameters vary with both power plant design and fuel, and many variations can be encountered (9). For this study, balanced draft boiler design is assumed along with the following combustion - emission parameters.

1. Coal-fired units—Flue gas compositions are based on combustion of pulverized coal with 20% excess air to the boiler, and 13% additional air inleakage at the air preheater. These values reflect operating experience with TVA horizontal, frontal-fired, coal-burning units. It is assumed that 75% of the ash present in coal is emitted as fly ash and 92% of the sulfur in the coal is emitted as SO_2.
2. Oil-fired units—A tangential-fired boiler is considered for oil-fired power units with flue gas compositions estimated assuming 5% excess air to the boiler with an estimated 10% air inleakage at the preheater. It is also assumed that all of the ash and sulfur in the fuel oil is emitted.

Flue gas compositions include a SO_X concentration, fly ash loading, and NO_X concentration as presented in table 4. These parameters depend primarily upon sulfur and ash content of the fuel, excess air, air inleakage, and boiler design. Nitrogen oxide compositions of flue gas are based on representative data for common boiler types for both coal- and oil-fired units (2, 3, 48); fly ash emission is based on relatively high ash emission factors to insure satisfactory design for removal of particulates.

Existing coal-fired units are assumed to have 98.7% efficient electrostatic precipitators already in operation which meet Federal new source emission standards. For new coal-fired units, fly ash collection facilities are provided in the process designs. Fly ash emission assumed from new and existing oil-fired units does not exceed the EPA particulate emission standard; therefore, these power plants do not require fly ash collection facilities.

Some aspects of design and economics for SO_2 removal units depend on fan and duct configuration and, for some processes, on the number of economizers and air heaters; therefore, consideration is given to their corresponding locations. A balanced-draft power unit without an SO_2 removal unit normally requires one induced-draft fan per duct capable of overcoming a pressure drop of approximately 15 inches downstream of the boiler. In the design of new power plants with SO_2 removal facilities it is assumed

Table 4. Estimated Flue Gas Compositions for Power Units Without Emission Control Facilities

Fuel and boiler type	Coal-fired boiler pulverized coal (horizontal, frontal-fired)			Oil-fired boiler (tangential-fired)		
Sulfur content of fuel, % by wt	2.0	3.5	5.0	1.0	2.5	4.0
Flue gas composition, % by volume						
Nitrogen	74.62	74.55	74.49	73.83	73.73	73.64
Carbon dioxide	12.57	12.55	12.54	12.52	12.37	12.21
Oxygen	4.86	4.86	4.85	2.55	2.55	2.54
Water	7.77	7.76	7.75	11.03	11.19	11.37
Sulfur dioxide	0.12	0.22	0.31	0.05	0.14	0.22
Nitrogen oxides	0.06	0.06	0.06	0.02	0.02	0.02
Fly ash loading						
Grains/scf dry	4.11	4.11	4.11	0.036	0.036	0.036
Grains/scf wet	3.79	3.79	3.79	0.032	0.032	0.032

Table 5. Power Plant Flue Gas and Sulfur Dioxide Emission Rates

Power plant size, MW	Type plant	Sulfur content of fuel, %	Gas flow to SO_2[a] recovery systems, M acfm (310° F)	Equivalent SO_2 emission rate to SO_2 recovery systems lb SO_2/hr
Coal-fired units				
200	New	3.5	630	9,310
200	Existing	3.5	650	9,610
500	Existing	3.5	1,570	23,270
500	New	2.0	1,540	13,010
500	New	3.5	1,540	22,760
500	New	5.0	1,540	32,510
1,000	Existing	3.5	3,080	45,520
1,000	New	3.5	2,980	44,000
Oil-fired units				
200	New	2.5	530	4,960
500	New	1.0	1,300	4,850
500	New	2.5	1,300	12,140
500	New	4.0	1,300	19,420
500	Existing	2.5	1,320	12,410
1,000	New	2.5	2,510	23,470

[a] Gas flows to new Cat-Ox installations are different from those shown above because of the higher gas temperature (890°F) and relocation of the air heaters.

that the balanced-draft system includes the same capacity F.D. fan; one I.D. fan is provided per duct downstream of the SO_2 removal system to overcome the remaining pressure drop resulting from power generation and the additional pressure drop attributed to SO_2 removal. Since existing power units are already equipped with a 15-inch I.D. fan, existing SO_2 removal facilities are provided with one supplemental fan per duct in series and adjacent to the existing fan to supply the additional energy required for the scrubbing facilities. In existing Cat-Ox processes, however, the supplemental fan is located downstream of the recovery unit. In this evaluation, 200-MW power units are assumed to have two economizers, air heaters, and exhaust ducts, and 500- and 1,000-MW units are assumed to be equipped with four of each.

The design of SO_2 removal facilities is dependent upon actual quantities of gas and SO_2 as well as gas compositions indicated earlier. Calculated flue gas and equivalent SO_2 emission rates are tabulated in table 5.

PROCESS DESIGN

Emission Standards

The EPA has established emission standards (10) for new steam generating facilities as shown in table 6. In this report, process and equipment design will meet the standards for particulate and SO_2 emission.

Degree of Removal

From the analyses of flue gas and Federal emission standards it can be seen that required SO_2 removal efficiencies vary depending on the sulfur content and type of fuel. The required removal efficiencies for particulates and SO_2 are given in table 7 for the various fuels and sulfur levels considered in this study. Base case design provisions

Table 6. EPA Emission Standards for New Steam Generating Facilities

	Allowable emission, lb/million Btu heat input	
	Coal-fired unit	Oil-fired unit
Particulates	0.1	0.1
Sulfur dioxide	1.2	0.8

Table 7. Required Removal Efficiencies

Sulfur content of fuel, %	Degree of particulate removal, %	Degree of SO_2 removal, %
Coal-fired units		
2.0	98.7	58.9
3.5	98.7	76.3
5.0	98.7	83.4
Oil-fired units		
1.0	–	26.0
2.5	–	70.4
4.0	–	81.5

are for 90% SO_2 removal rather than for meeting minimum requirements or for operating at maximum process capability. Special cases with design provisions for 80% SO_2 removal (corresponding to a guaranteed design to exceed the emission regulation of 76.3%) are prepared for new 500-MW, 3.5% S, coal-fired units for comparison of economics with the base case.

Scrubber Redundancy, Bypass, Turndown, and Shutoff

Scrubbing system design assumes that technology used in each process is proven, has been demonstrated, and is not "first of a kind." No special redundancy provisions are assumed necessary for power-SO_2 scrubbing system reliability.

Several methods are available to provide turndown capabilities of the control systems resulting from changes in power supply requirements including:

1. Multiple scrubbing trains.
2. Variable flow control to individual scrubbers.
3. Compartmentalized scrubbers.
4. Individual scrubber bypasses.
5. Connecting plenum ducts between trains.

These different methods affect both duct and scrubber design and, unfortunately, little experience is available to indicate which method is best. For this study, boiler ducts are assumed to exhaust to a common plenum connecting the scrubbing trains. Separate ducts from the plenum to each scrubbing train are equipped with dampers for individual scrubber shutoff for maintenance or power plant turndown. Scrubber circulation systems are provided with constant speed pumps based on pumping rates corresponding to the design L/G. Because of the reliability implied in the assumption that these processes are not "first of a kind," other special design provisions for individual scrubber shutdown are not provided. If one of the scrubbing trains is required to shut down, the power generation facilities would be required to cut back on operation so as not to exceed the design conditions for any individual scrubber. The common feed plenum provides for the shutdown of a scrubbing train during restricted operation of power plants due to low electrical demand or required maintenance of the SO_2 removal facilities.

Bypass ducts for maintaining full power generation capacity during shutdown of one or more scrubbing trains are not provided except for the Cat-Ox process. For this process, they are required to prevent contamination of the catalyst and acid during power plant startup when the electrostatic precipitators may not yet be operating at design efficiency. For illustrative purposes, the additive cost effect of designing a limestone scrubbing system with bypass ducts is shown in table 79(p. 162) of the "Economic Evaluation and Comparison" section under "Accuracy of Results." The results for other systems might vary depending on layout.

Particulate and Sulfur Dioxide Control Devices

Venturi scrubbers are chosen for control of particulates in the limestone, lime, magnesia, and sodium scrubbing processes since they are generally considered to be the least cost alternative. The Cat-Ox process, however, requires a high degree of particulate removal (to 0.005 gr/scf) prior to conversion of SO_2 to SO_3 at elevated temperatures for both coal- and oil-fired units; therefore, fly ash is removed by high efficiency electrostatic precipitators. As discussed earlier, all existing coal-fired units are assumed to be equipped with 98.7% efficient electrostatic precipitators; therefore, only the Cat-Ox process requires additional facilities for supplemental particulate control. Table 8 indicates the various devices selected for particulate and SO_2 control in the current study.

Although specific design conditions for SO_2 removal systems may vary from installation to installation corresponding to expected fluctuations in the analysis of the fuel or proposed operating requirements, the projected operating parameters for each base case scrubbing system are presented in table 9.

Mist Eliminator Selection

The use of a mist eliminator in the SO_2 scrubber is desirable for the following purposes:

1. To reduce the heat load on the stack gas reheater.
2. To decrease the deposition of liquid and entrained solids in ducts and equipment located downstream from the scrubber.
3. To reduce the amount of entrained solids emitted to the atmosphere.

For maximum efficiency and extended service, mist eliminators should be designed for proper gas distribution and include facilities for removing any accumulated solids. Several types of mist eliminators are being used. From limited experience and scrubber vendors' recommendations, the following mist eliminators are selected for each of the processes:

Process	Mist eliminator
Limestone	Chevron vane
Lime	Chevron vane
Magnesia	Chevron vane
Sodium	Fleximesh
Cat-Ox	Brink fiber demister

Reheat

The need for stack gas reheat for plume buoyancy after aqueous scrubbing has been recognized, but the degree of

Table 8. Particulate and Sulfur Dioxide Control Devices

Process	Status	Equipment	
		Particulate control	SO_2 control
Coal-fired units			
Limestone	New	One-stage venturi[a]	Two-bed mobile bed
	Existing	ESP	Three-bed mobile bed
Lime	New	One-stage venturi[b]	One-stage venturi[b]
	Existing	ESP	Two-stage venturi[b]
Magnesia	New	One-stage venturi	One-stage venturi
	Existing	ESP	One-stage venturi
Sodium	New	One-stage venturi	Valve-tray absorber
	Existing	ESP	Valve-tray absorber
Cat-Ox	New	High temperature, high efficiency, ESP	Packed-bed absorber
	Existing	ESP + additional ESP for removal to 0.005 gr/scf	Packed-bed absorber
Oil-fired units			
Limestone	New	–	Three-bed mobile bed
	Existing	–	Three-bed mobile bed
Lime	New	–	Two-stage venturi[b]
	Existing	–	Two-stage venturi[b]
Magnesia	New	–	One-stage venturi
	Existing	–	One-stage venturi
Sodium	New	–	Valve-tray absorber
	Existing	–	Valve-tray absorber
Cat-Ox	New	High temperature, ESP	Packed-bed absorber
	Existing	ESP	Packed-bed absorber

[a] Spent SO_2 scrubber effluent used as scrubbing media.

[b] Approximately 78% of the required lime is fed to the first venturi

Table 9. Assumed Operating Parameters for Scrubbing Systems Applied to New Coal-Fired Power Units (Design Conditions–3.5% S Coal, 2,200 ppm SO_2 in Inlet Gas, 90% Nominal SO_2 Removal)

Process	Limestone	Lime	Magnesia	Sodium	Cat-Ox
Stoichiometry	1.20	1.10	1.05	1.05	–
Design gas velocity, ft/sec					
Particulate scrubber	125-140	125	125-140	125-140	–[a]
SO_X scrubber	10	100	75	8	8
L/G, gal/mcf					
Particulate scrubber	15	40	15	15	–
SO_X scrubber	70	40	20	3[b]	5
Design pressure drop, in H_2O					
Particulate scrubber	10	10	8.5	8.5	–
SO_X scrubber	10	6	4.5	10.0	23
Percent solids in slurry					
Particulate scrubber	8+ fly ash	5+ fly ash	5	5	–
SO_X scrubber	8	5	10	0	–
Liquid residence time, minutes					
Particulate scrubber effluent	5	3	3	3	–
SO_X scrubber effluent	10	3	3	–	–

[a] 99.9% high temperature ESP.

[b] Separate circulation loops are provided for each stage.

reheat required has not been well established. The effect of temperature on plume buoyancy and ground-level concentration of stack gas constituents was studied in detail for the limestone - wet scrubbing conceptual design (57). The results indicated that with a high degree of SO_2 removal (80% or above), the stack gas temperature is not critical. However, to prevent high ground-level concentrations during adverse conditions, reheat to 175°F is provided in these comparative designs.

Some reheat is obtained from exhaust gas compression when I.D. fans are used, but additional heat is needed to reach 175°F at the stack exit. Approximately 4°F of reheat are assumed lost as the gas passes through the stack. The magnesia process obtains some reheat from the dryer offgas. For new coal-fired power units, indirect steam reheat is provided since new power units can be designed to supply steam to the scrubbing area. In cases of existing coal-fired and both new and existing oil-fired power units, direct stack gas reheat is provided from the combustion of fuel oil.

The Cat-Ox process does not require stack gas reheat since the scrubbed gas exits at a temperature of 254°F. Existing Cat-Ox units, however, require reheat of the flue gas upstream of the converter. This reheat is supplied by direct oil-fired gas reheat; however, operation of the Wood River Cat-Ox installation has indicated the need to control particulate formation to a high degree during combustion of the oil to prevent fouling of the converter catalyst.

Of the various methods for reheat of the stack gas, indirect steam and direct oil-fired reheat are probably the simplest to install, most reliable for their respective applications, and are probably in the mid-cost range as compared to other choices.

Raw Materials

Listed below are the raw materials which are utilized in the five desulfurization processes, with assumptions for inventory and typical characteristics given. Raw materials and catalysts which are considered proprietary are not shown.

1. Limestone
    - Purchase size - 0 x 1-1/2 in.
    - Analysis - 90% $CaCO_3$ (dry), 5% H_2O
    - Limestone ground as 60% solids slurry
    - Ground size - 70% -200 mesh
    - Bulk density - 95 lb/ft³
    - Storage capacity - 30 days
2. Lime
    - Analysis - 95% CaO, 1% SiO_2, 2% MgO
    - Size is -1-1/4 in. +3/4 in.
    - Bulk density - 55 lb/ft³
    - Storage capacity - 5 days (from "across the fence" calcination plant)
3. Magnesium oxide
    - Calcined magnesite - 98% MgO
    - Fine crystalline powder
    - Bulk density - 20-30 lb/ft³
    - Makeup MgO storage - 30 days
4. Coke (petroleum)
    - Analysis
        - Typical - 4.2% S, 0.1% ash, 9.0% volatile matter, 100 ppm vanadium
        - Contract - 5.0% S maximum, 1.0% ash maximum, 7.0% volatile matter minimum, 200 ppm vanadium maximum
    - Size is -1-1/2 in.
    - Calorific value - 15,510 Btu/lb
    - Storage - 30 days
5. Sodium carbonate
    - Analysis - 99.8% Na_2CO_3 (58.36% Na_2O)
    - Light soda ash
    - Bulk density - 35.5 lb/ft³
    - Storage capacity - 5 days
6. Vanadium pentoxide catalyst
    - Pellets
    - Size - 100% +7/32 in. diameter, 7/16 in. long
    - Bulk density - 36.8 lb/ft³

In-Process Storage

To give some flexibility of operation, in-process storage is included to provide for interrupted service of certain equipment. The amount of in-process storage provided for each process is shown below.

1. Limestone process
    a. Crusher feed bin - 8 hr.
    b. Slurry feed tank - 8 hr.
    c. Pond feed tank - 62,000 gal (includes sufficient surge capacity for shutdown of scrubbers).
2. Lime process
    Process bin - 8 hr
3. Magnesia process
    a. $MgSO_3$ storage silo - 1 day.
    b. Recycle MgO storage silo - 1 day.
    c. First-stage venturi scrubber surge tank - 40,600 gal (includes sufficient surge capacity for shutdown of first-stage venturi scrubber).
4. Sodium process
    a. Soda ash storage bin - 5 days.
    b. Dissolving tank - 8 hr.
    c. Surge tank - 8 hr.
    d. Centrate tank - 3 min.
5. Cat-Ox process - none required.

Solids Disposal

One important design consideration for the limestone and lime slurry processes is the method for waste solids disposal. The following two alternatives are utilized in this study.

1. On-site disposal—A common pond for fly ash and calcium solids is assumed for new power units. For existing coal-fired power units, the existing ash disposal pond is enlarged to accommodate the calcium solids. This method of disposal is based on the following assumptions:
    a. Pond life is same as power plant remaining life defined earlier in power plant design premises.
    b. About one-sixth of the total interstitial water is put into pond for startup.
    c. Pond is lined with impervious clay and has a depth of 40 ft.
    d. Water is recycled back to the scrubbers to minimize the consumption of fresh water and to eliminate contamination of nearby streams.
    e. Sludge contains 60% free water.
    f. Pond evaporation and seepage equals rainfall.
2. Off-site alternative—A special case is evaluated (for both the limestone and lime slurry processes) in which the fly ash and calcium solids are trucked to and disposed of off-site. Each process is designed with a slurry dewatering system to produce a disposal cake containing 50% solids. Sufficient charges (44) per ton of wet solids are applied to cover trucking and stabilization off-site.

Product Storage Capacity

The amount of storage which should be provided for a product depends largely upon its consumption rate for each end use. Since sulfuric acid, sulfur, and sodium sulfate are intermediate products which usually undergo further processing, the largest burden is often passed on to the industrial consumer rather than the producer. However, to provide for large consumer and cyclic markets such as the phosphate fertilizer industry, storage requirements of 30 days or more are not uncommon. In this study, product storage requirements are as follows:

Process	Product	Storage
Magnesia	98% H_2SO_4	30 days
Sodium	Molten sulfur	30 days
Sodium	Sodium sulfate	7 days
Cat-Ox	80% H_2SO_4	30 days

ECONOMIC

To evaluate the economics of several processes at the same time, a set of common criteria (6, 51) is assumed including plant location, cost indices, raw material prices, method of financing, taxes, and other special provisions. Two of the more significant items of comparison are capital investment and operating costs.

Capital Investment

The numerous investment estimates are based on a midwestern location with assumed land costs of $3,000/acre and represent projects beginning mid-1972, ending mid-1975, with an average cost basis for scaling of mid-1974. Other projects may be scaled from mid-1974 to the midpoint of project expenditures. The first 6-12 months are for design and the last 24 months for construction during the 30-36 months project. Fixed investments are prepared using the following Chemical Engineering plant cost index and projections (58).

Year	1962	1963	1964	1965	1966	1967	1968
Material	100.6	100.5	101.2	102.1	105.3	107.7	111.5
Labor	105.6	107.2	108.5	109.5	112.5	115.8	120.9

Year	1969	1970	1971	1972[a]	1973[a]	1974[a]
Material	116.6	123.8	130.4	135.4	142.2	153.8
Labor	128.3	137.4	146.2	152.2	161.3	177.9

[a] Projections.

Other special provisions or assumptions required to prepare uniform cost estimates are as follows:

1. Equipment, material, and construction labor shortages with accompanying overtime pay incentive are not considered.
2. Service facilities such as maintenance shops, stores, communications, security, and offices are estimated or allocated on the basis of process requirements using current TVA practice as a guide.
3. Direct investments for each of the processes include cost for 1 mile of paved roads.
4. Railroad facilities vary with each process depending upon raw material and utility usage in addition to the type process, i.e., throwaway or recovery.
5. Electrical switchyard locations are arbitrarily assumed to be approximately 300 yards from the control rooms.
6. Control room location varies with each process depending upon equipment size and configuration whereas the Cat-Ox process shares the power plant control room. In the other processes, the control rooms are located adjacent to the scrubbing facilities and approximately [illegible] feet from the powerhouse.
7. As required for each process, necessary electrical substations and conduit, steam, natural gas, fuel oil storage, process water, fire and service water, and compressed air distribution facilities are included in the investment.

8. Instrument air generation facilities are included for each process. Steam is assumed not available from the power plant cycle at existing units. Fuel oil is used to replace steam whenever possible for existing coal-fired and both new and existing oil-fired units. In the sodium process regeneration area for existing units, a package boiler is used for steam generation. Where it is acceptable to tap into the existing steam cycle (availability for production of power) a savings in steam costs could be incurred because of the low cost of coal in comparison to fuel oil. Generation facilities for electricity are not included in the investments.
9. Process water utilization is based on closed-loop operation.
10. Spare pumps are provided to prevent operational shutdowns due to pump failure; however, no other spare equipment is included.
11. Solids disposal ponds are assumed to be 1 mile from the scrubbing systems.
12. New coal-fired units are designed for the removal of both fly ash and SO_2. The catalytic oxidation process utilizes an electrostatic precipitator for removal of fly ash upstream of the SO_2 removal facilities. The aqueous scrubbing processes utilize wet scrubbing devices for removal of both fly ash and SO_2. As illustrated in tables 35-44 and 59-68, both investment and operating costs for removing fly ash are included in the process economics but both investment and operating costs for ash disposal are excluded.

    Existing coal-fired units are assumed to already be equipped with electrostatic precipitators capable of meeting the EPA fly ash emission standard (98.7% removal) and supplementary facilities for disposal. Therefore, with the exception of the Cat-Ox process, investment and operating costs for existing units do not include supplementary fly ash collection facilities. The Cat-Ox process requires a higher degree of fly ash removal (99.9% overall removal for coal-fired units and 84.4% removal for oil-fired units) to prevent accelerated blinding of the catalyst and contamination of acid. Additional electrostatic precipitators are supplied for the Cat-Ox process to increase the overall collection efficiency to these levels.
13. In the limestone and lime slurry processes where fly ash and calcium solids are removed and disposed together, the investment and operating costs for the disposal area are prorated to include only the costs attributed to calcium solids disposal.
14. For new units, the incremental investment or operating cost attributed to fans is estimated as the difference in investment or operating cost of the higher energy fan and a 15 inch ΔP capacity fan which would be required if scrubbing facilities were not to be installed. For existing units the total investment and operating costs of the supplemental fans are included.
15. Direct investment costs include construction facilities equivalent to 5% of the direct area investments. These allowances are based on TVA experience and include costs for mobile equipment, temporary lighting, construction roads, raw water supply, safety and sanitary facilities, and other similar expenses incurred during construction, but not broken down and assigned to any specific area.

In addition to direct costs which include equipment, installation, labor and materials, and construction facilities, indirect costs for the project, which include engineering design and supervision, construction field expense, contractor's fees, and contingency are included in the investment estimates. The engineering design and supervision and contingency factors are based on proven design, not "first of a kind" installation. The percentages of direct investment used to estimate these items are shown in table 10. These factors are based on established methods for estimating indirect investment costs and agree with the general range of projected values indicated in various cost estimating sources (34). Slightly lower values of engineering design and supervision are projected for the throwaway processes than for the recovery processes reflecting less complex engineering design and construction.

In keeping with FPC accounting practice, allowances are included for startup and modification plus interest during construction. Startup and modification allowances are estimated as 10% of subtotal fixed investment for the recovery processes compared to 8% for the throwaway processes reflecting the greater complexity of product producing processes. Interest during construction is estimated as 8% of the subtotal fixed investment for each process. This factor is equivalent to the simple interest which would be accumulated at an 8% per year rate assuming a capital structure of 50% debt-50% equity (see table 14) and a 3-year project expenditure schedule as indicated below:

Project Expenditure Schedule

	Year			
	1	2	3	Total
Fraction of total expenditure as borrowed funds	1/8	1/4	1/8	1/2
Simple interest at 8%/year as percent of total expenditure				
Year 1 debt	1	1	1	3
Year 2 debt	—	2	2	4
Year 3 debt	—	—	1	1
Accumulated interest as percent of total expenditure	1	3	4	8

Table 10. Indirect Investment and Allowance Factors

Power unit size and status	Throwaway processes, percentage of direct investment					
	200 MW		500 MW		1,000 MW	
	New	Existing	New	Existing	New	Existing
Engineering design and supervision[a]	11	12	9	10	8	9
Construction field expense	13	15	11	13	10	12
Contractor's fees	7	9	5	7	5	7
Contingency[a]	11	12	10	11	9	10
Total indirects	42	48	35	41	32	38

Allowance for startup and modification (8% of subtotal fixed investment); interest during construction at 8%/year rate (8% of subtotal fixed investment)

Power unit size and status	Recovery processes, percentage of direct investment					
	200 MW		500 MW		1,000 MW	
	New	Existing	New	Existing	New	Existing
Engineering design and supervision[a]	13	14	11	12	10	11
Construction field expense	13	15	11	13	10	12
Contractor's fees	7	9	5	7	5	7
Contingency[a]	11	12	10	11	9	10
Total indirects	44	50	37	43	34	40

Allowance for startup and modification (10% of subtotal fixed investment); interest during construction at 8%/year rate (8% of subtotal fixed investment)

[a] Based on proven design rather than a "first of a kind" installation, a minimum amount of contingency is included. For a "first of a kind" installation, contingency would normally be greater than that shown above.

Operating Cost Basis

To prepare meaningful operating cost estimates, several more ground rules and inputs must be defined. Some of these have been discussed previously, such as those parameters necessary to produce flowsheet calculations. Others are defined here to permit calculation of annual, lifetime, and unit operating costs.

All annual operating cost display sheets are based upon 7,000 hours of operation per year. Process operation schedules are assumed to be the same as the power plant operating profiles and remaining life assumptions given in the power plant design premises.

Operating costs related to the removal and disposal of fly ash are estimated similar to the investment costs. Cost for new coal-fired units include the removal of fly ash, whereas existing coal-fired and both new and existing oil-fired units (except for Cat-Ox) do not. However, operating costs are prorated to exclude costs for the disposal of fly ash.

Charges for the disposing of solids off-site include investment, treatment, transportation, and land costs. The base trucking, off-site treatment, and land costs for disposing calcium solids is assumed to be $4/ton (44) of wet solids (50% free moisture in cake).

Raw material, labor, and utility costs are projected to 1975. Although costs for these items vary throughout the country, representative values projected for this study (59) are shown in table 11. (All tonnages are expressed as short tons.)

Unit costs for steam and electricity generated by the power plant are based on actual production cost including labor, fuel, depreciation, rate base return on investment, and taxes.

In the evaluation of lifetime economics, credit from sale of byproducts is deducted from the yearly projections of operating cost to give the net effect of the pollution process on the cost of power. Table 12 shows the base product credits assumed in the study (13, 18, 29, 30, 36, 53) and the range of values for which the sensitivity of lifetime economics to net product revenue is evaluated (see figures 82-87).

Maintenance costs are estimated on the basis of direct investment and are varied for each process as a function of unit size corresponding to an assumed economy of scale. The maintenance percentages applied are considered "best estimates" and are derived by using comparable percentages for common process areas as illustrated in operating cost breakdown tables 59-68 shown in the "Economics section." Table 13 shows the estimated equivalent overall annual maintenance factors which are applied to the direct investment for each process, corresponding to an annual operating schedule of 7,000 kWh/kW capacity. Maintenance factors for other operating schedules are scaled exponentially. In addition to utilizing the base factors indicated in the table, the sensitivity of operating costs to variations in maintenance requirements for the magnesia slurry scrubbing process is evaluated and presented in figure 58 of the "Results" section.

Estimation of operating cost is complicated by the fact, as discussed in the ammonia scrubbing conceptual design study (56), that projects for sulfur and nitrogen oxides control in power plants may be financed on different bases the regulated power industry basis, the nonregulated chemical industry practice, or a combination of the two. This has a major effect on capital charge items such as depreciation and taxes. This study is based upon regulated company economics and a breakdown of the capital charges is given in table 14. The depreciation rate is straight line based on the remaining life of the power plant after the pollution control process is installed.

In estimating the regulated capital charges associated with stack gas scrubbing, the conventional method of considering the overall life of the power plant is used. The FPC recognizes the conclusion of the National Power Survey that a 30-year service life is reasonable for steam-electric plants (14). Because some items have life spans less than 30 years, however, the FPC has designated interim replacements as an allowance factor to be used in estimating annual operating costs to provide for the replacement of such items. Use of this allowance following FPC recommended practice provides for financing the cost of replacing such short-lived units. An average allowance of about 0.35% of the total investment is normally provided. However, to provide for the unknown life span of SO_2 control facilities, a somewhat larger allowance factor is used for new units. An insurance allowance is also included in the capital charges based on FPC practice.

Debt-equity ratio is another component of capital charges for which variations of ratios may be expected. However, FPC data (15, 16) indicate that the long-term debt for privately owned electric utilities varied only slightly from 51.5% to 54.8% of total capitalization during the period 1965-1973. For this study, a 50/50 debt-equity ratio is assumed, corresponding to an overall cost of money of 10%.

Since most regulatory (19, 54) commissions base the annual permissible return on investment on the remaining depreciation base (that portion of the original investment yet to be recovered or "written off"), a portion of the annual capital charge included in the lifetime operating

Table 11. Projected 1975 Unit Costs for Raw Materials, Labor, and Utilities

Raw materials			$/unit
Limestone			4.00/ton
Lime			
Lime process			20.50-26.00/ton[a]
MgO process			26.00/ton
Sodium process			26.00/ton
Magnesium oxide			155.00/ton
Coke			15.00/ton
Vanadium pentoxide catalyst			
MgO process			1.65/liter
Cat-Ox process			1.65/liter
Sodium carbonate			52.00/ton
Antioxidant (sodium process-scrubbing)			2.00/lb
Catalyst (sodium process - SO_2 reduction)			_b
Labor			
Operating labor			8.00/man-hr
Analyses			12.00/hr
Utilities (59)	200 MW	500 MW	1,000 MW
Fuel oil, No. 2	0.30/gal	0.30/gal	0.30/gal
Fuel oil, No. 6	0.23/gal	0.23/gal	0.23/gal
Natural gas	1.00/mcf	1.00/mcf	1.00/mcf
Steam (500 psig)			
Coal-fired units	0.80/M lb	0.70/M lb	0.60/M lb
Oil-fired units	1.50/M lb	1.40/M lb	1.30/M lb
Process water[c]		0.02-0.08/M gal[c]	
Electricity			
Coal-fired untis	0.011/kWh	0.010/kWh	0.009/kWh
Oil-fired units	0.019/kWh	0.018/kWh	0.017/kWh
Heat credit			
Coal-fired units	0.60/MM Btu	0.60/MM Btu	0.60/MM Btu
Oil-fired units	1.60/MM Btu	1.60/MM Btu	1.60/MM Btu

[a] Varies according to annual quantity requirements.

[b] Unit costs supplied by Allied Chemical; catalyst not identified.

[c] Varies according to water volume requirements which are process dependent.

Table 12. Product Credit

Process	Products	Assumed revenue	
		Base	Variations
Magnesia	98% H_2SO_4	\$8/short ton 100% H_2SO_4	\$0-\$32
Sodium	Sulfur	\$25/short ton	\$15-\$40
Sodium	Sodium sulfate	\$20/short ton	–
Cat-Ox	80% H_2SO_4	\$6/short ton 100% H_2SO_4	\$0-\$30

Table 13. Estimated Overall Annual Maintenance Costs

Process	Percentage of direct investment		
	200 MW	500 MW	1,000 MW
Limestone	9	8	7
Lime	9	8	7
Magnesia	8	7	6
Sodium	7	6	5
Cat-Ox	5	4	3

costs declines uniformly over the life of the power plant.

Because of the wide variations that exist in the breakdown of capital charges, the sensitivity of operating costs to variations in capital charges and cost of money is presented in figures 54-56 and 89-93 of the "Results" section.

Plant, administrative, and marketing overheads are costs which vary from company to company. With consideration of the various methods used in industry and illustrated in a variety of cost estimating sources (4, 34), the following method of estimating overheads is used.

Plant overheads are estimated as 20% of the subtotal conversion costs, which includes the projected costs for labor, utilities, maintenance, and analyses. Administrative overheads for the throwaway processes are estimated as 10% of operating labor and supervision. For the magnesia process, administrative and marketing overhead is estimated as 11% of the subtotal conversion costs. Sodium and Cat-Ox administrative and marketing overheads are estimated on the basis of the relative difficulty in marketing the various products in comparison to magnesia product marketing costs.

Working Capital

Working capital consists of the total amount of money invested in raw materials and supplies carried in stock, finished products in stock and semifinished products in the process of being manufactured, accounts receivable, cash kept on hand for monthly payment of operating expenses, such as salaries, wages, and raw material purchases, accounts payable, and taxes payable. Several methods are illustrated throughout the literature for estimating the working capital requirements of a given process (4, 34). For this study, working capital is defined as the equivalent cost of 3 weeks of raw materials, 7 weeks of direct operating costs, and 7 weeks of overheads. Working capital requirements are calculated for each case evaluated and presented at the bottom of the annual operating cost estimates shown in Appendix B.

Table 14. Annual Capital Charges for Power Industry Financing

	As percentage of original investment		
	Years remaining life		
	30	25	20
Depreciation-straight line (based on years remaining life of power unit)	3.33	4.00	5.00
Interim replacements (equipment having less than 30-yr life)	0.67	0.40	–
Insurance	0.50	0.50	0.50
Total rate applied to original investment	4.50	4.90	5.50
	As percentage of outstanding depreciation base[a]		
Cost of capital (capital structure assumed to be 50% debt and 50% equity)			
Bonds at 8% interest		4.00	
Equity at 12% return to stockholder		6.00	
Taxes			
Federal (50% of gross return or same as return on equity)		6.00	
State (national average for states in relation to Federal rates)		4.80	
Total rate applied to depreciation base		20.80[b]	

[a] Original investment yet to be recovered or "written off."

[b] Applied on an average basis, the total annual percentage of original fixed investment would be 4.5% + ½ (20.80%) = 14.90%.

Systems Estimated

Process descriptions, flowsheets, layout drawings, and equipment requirements for the five processes are presented in this section. Each process is subdivided into several major functional areas to facilitate comparisons of investment and operating costs for similar processing steps. Costs for land, piping, electrical, instrumentation, ductwork, structures, foundations, and painting are included in each area along with the process equipment. Discussion of specific items which may be required for process design, but are assumed to be supplied by the power facility or whose costs are prorated between the power unit and the control facility, are provided where applicable.

Following current practices, the material of construction for ductwork between the powerhouse and the scrubbers is insulated Cor-Ten. Ductwork between the scrubbers and the stack gas reheater system is epoxy-lined mild steel for the limestone, lime, magnesia, and sodium processes and insulated Cor-Ten for the Cat-Ox process. The I.D. fans and the ductwork between the reheater and the stack are Cor-Ten since these areas require some protection from reheat failure. Unless otherwise noted, materials of construction for process equipment are assumed to be carbon steel.

Process descriptions and drawings are presented for each of the five processes followed by an area-by-area analysis of equipment requirements and methods of costing based upon the "Power Plant, Process Design, and Economic Premises" section.

LIMESTONE SLURRY PROCESS

Removal of SO_2 from power plant stack gas using the limestone slurry process is accomplished by contacting the gas with a recirculating slurry containing wet-ground limestone and reaction products in a multi-bed mobile bed absorber. Incoming 0 x 1-1/2 inch limestone is received by either truck or rail and conveyed to a 30-day storage pile located about 150 feet from the grinding facilities. The limestone is reduced to about 0 x 3/4 inch using gyratory crushers, wet-ground to 70% -200 mesh in two parallel ball mills, and stored as a 60% solids slurry in a feed tank with 8 hours storage capacity.

The limestone makeup slurry is fed to the absorber hold tanks where it is combined with effluent slurry from the scrubbers and recycle pond water to maintain a 10% solids slurry. The SO_2 is reacted with the slurry by circulation through the mobile bed absorbers which are equipped with chevron-type entrainment separators designed for upstream wash with fresh makeup water. A bleed stream of partially spent slurry overflows to the particulate scrubber hold tanks and is circulated through the particulate venturi scrubber for removal of fly ash. The overflows from these tanks are fed to one pond feed tank with a surge capacity equal to the liquor holdup in the scrubbers. Existing coal-fired and both new and existing oil-fired units do not require particulate removal, therefore, the SO_2 absorber hold tank overflow is fed directly to the pond feed tank.

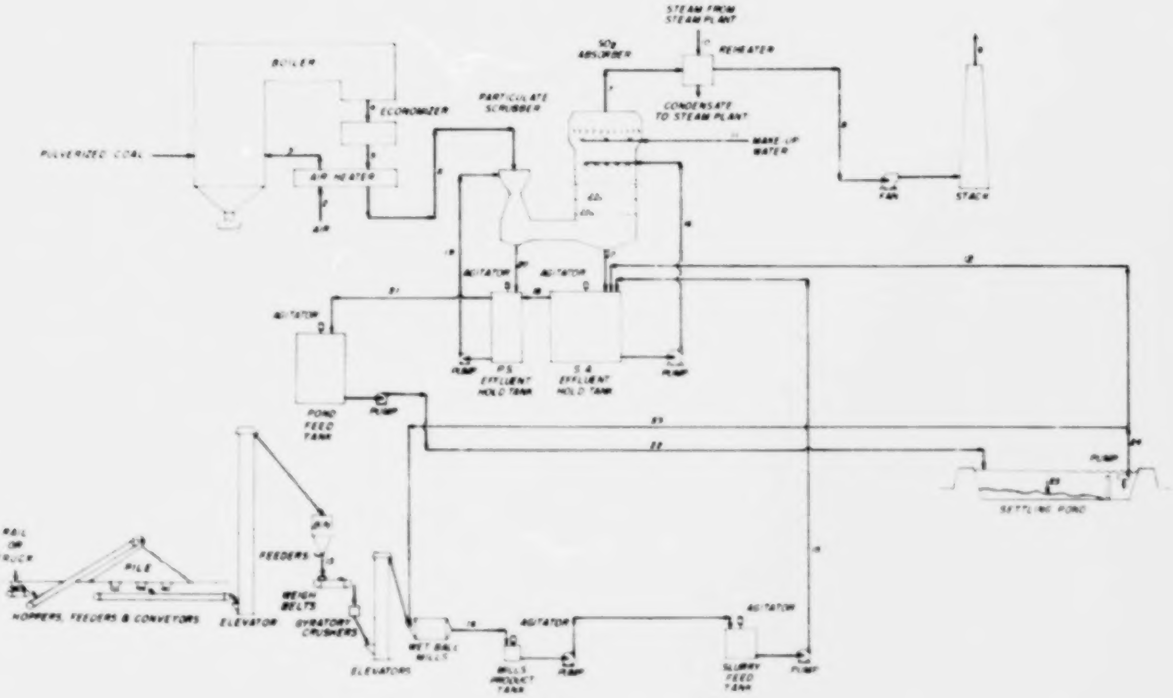
For new coal-fired units, the spent slurry, consisting of calcium compounds and fly ash, is pumped to the on-site pond where it settles to about a 40% solids slurry. Pond water is recycled to the wet ball mills and to the SO_2 absorber hold tanks to maintain a closed-loop process. A special case is evaluated in which the spent slurry is pumped to a slurry dewatering system to produce a disposal cake containing 50% solids; the cake is trucked to and disposed of off-site. The slurry dewatering system includes thickener tanks and rotary vacuum filters for processing the underflows from the thickener. Overflows from the thickeners are recycled to the wet ball mills and to the SO_2 absorber hold tanks. The total land requirement for the base case limestone slurry process is broken down as follows:

Process function	Land required, acre
Fly ash and SO_2 removal	8.0
Waste disposal	
Fly ash	75.0
Calcium solids	131.0

Excluding the disposal area required for fly ash as discussed in the premises, the total amount of land included in the limestone slurry process cost estimate is 139.0 acres. The flow diagram, material balance, control diagram, plot plan, and process layout and elevation drawings for the base case are shown in figures 1-5. The major areas are described in the following section.

Limestone Receiving and Storage

This area includes facilities for receiving raw limestone (-1-1/2 in.) by truck or rail, a storage stockpile, and live


PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
PARTICULATE SCRUBBER
SO2 ABSORBER
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
MAKE-UP WATER
FAN
STACK
AGITATOR
AGITATOR
AGITATOR
PUMP
P.S. EFFLUENT HOLD TANK
S.A. EFFLUENT HOLD TANK
PUMP
POND FEED TANK
PUMP
PUMP
SETTLING POND
RAIL OR TRUCK
PILE
HOPPERS, FEEDERS & CONVEYORS
ELEVATOR
FEEDERS
WEIGH BELTS
GYRATORY CRUSHERS
ELEVATORS
WET BALL MILLS
MILLS PRODUCT TANK
PUMP
AGITATOR
SLURRY FEED TANK
AGITATOR
PUMP
22
23
24
25

STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO PARTICULATE SCRUBBER	GAS TO REHEATER	GAS TO FAN	GAS TO ATMOSPHERE	STEAM TO GAS REHEATER	MAKE UP WATER TO SO2 ABSORBER	POND WATER TO S.A.E.H.T.	LIMESTONE TO WEIGH FEEDER	SLURRY TO MILLS PRODUCT TANK	LIMESTONE SLURRY TO S.A.E.H.T.	RECYCLE SLURRY TO SO2 ABSORBER	SO2 ABSORBER SLURRY TO S.A.E.H.T.	S.A.E.H.T. OVERFLOW TO P.S.E.H.T.
RATE, LBS/HR	[illegible]	[illegible]	[illegible]	4,604M	4,604M	[illegible]	[illegible]	[illegible]	[illegible]	170M	[illegible]	[illegible]	29M	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SCFM		[illegible]	[illegible]	947M	961M	[illegible]	[illegible]	[illegible]	[illegible]									
GPM											185	159		680	240	228M	25M	549
PARTICULATES, LBS/HR				33.7M	33.7M	6,433	55.9	55.9	224									
TEMPERATURE, °F		[illegible]	535	690	705	510	125	185	175	470								
SPECIFIC GRAVITY														[illegible]				[illegible]
VISCOSITY, CPS																		
UNDISSOLVED SOLIDS, %														60				8
pH											SEE NOTE 5							

STREAM NO	19	20	21	22	23	24	25
DESCRIPTION	RECYCLE SLURRY TO PART SCRBR	PART SCRBR SLURRY TO P.S.E.H.T.	P.S.E.H.T. OVERFLOW TO POND FEED TK	USED SLURRY FOR FLY ASH TO SETLG POND	SETTLED USED SLURRY & FLY ASH	RECYCLE POND WATER	POND WATER TO WET BALL MILL
RATE, LBS/HR	2,720M	2,677M	137M	567M	231M	338M	46M
SCFM							
GPM	4,900	4,823	247	988	350	677	262
PARTICULATES, LBS/HR							
TEMPERATURE, °F							
SPECIFIC GRAVITY			[illegible]		1.52		
VISCOSITY, CPS							
UNDISSOLVED SOLIDS, %			17		60		
pH			[illegible]		SEE NOTE 5	SEE NOTE 5	

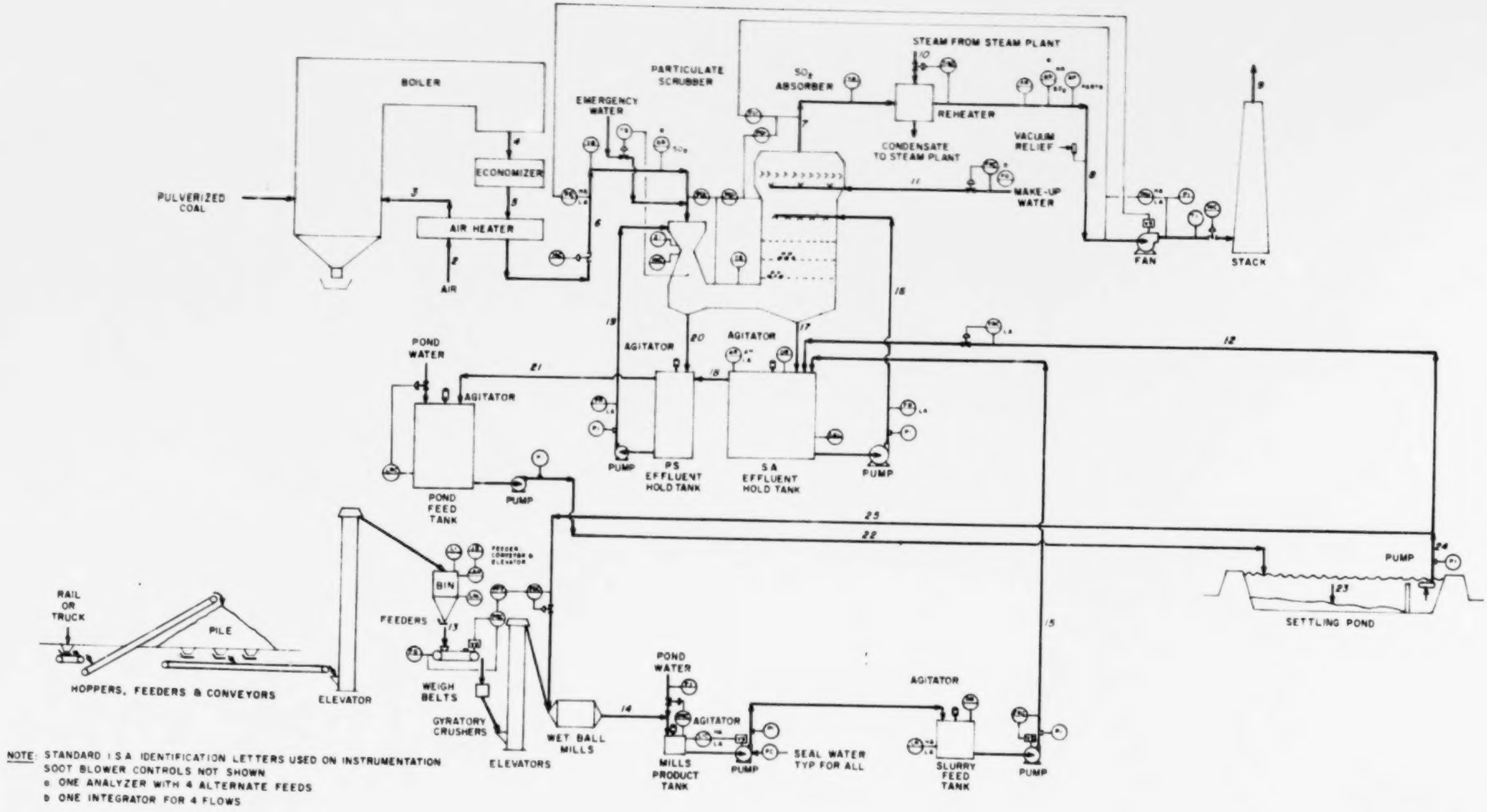
NOTES

1. CALCULATIONS BASED ON:
   - a. 120% STOICHIOMETRIC LIMESTONE: 90% $CaCO_3$ (DRY), 5% H_2O
   - b. 3.5% SULFUR IN COAL (DRY)
   - c. 16% ASH COAL (AS FIRED)
   - d. 92% OF SULFUR IN COAL EVOLVES AS SO_2
   - e. 75% OF ASH IN COAL EVOLVES AS FLY ASH
   - f. 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
   - g. 85% SO_2 REMOVAL
   - h. POND EVAPORATION AND SEEPAGE EQUALS RAINFALL
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS [illegible], 6, 10, 12 & 19, 21 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 13, 14 & 20 ARE ONE OF TWO SIMILAR STREAMS
5. RATES FOR LINES 11, 23 & 24 ASSUME ABOUT ONE SIXTH OF POND LIFE SETTLED SOLIDS INTERSTITIAL H_2O IS PUT INTO POND FOR STARTUP

SYMBOL IN TABLE

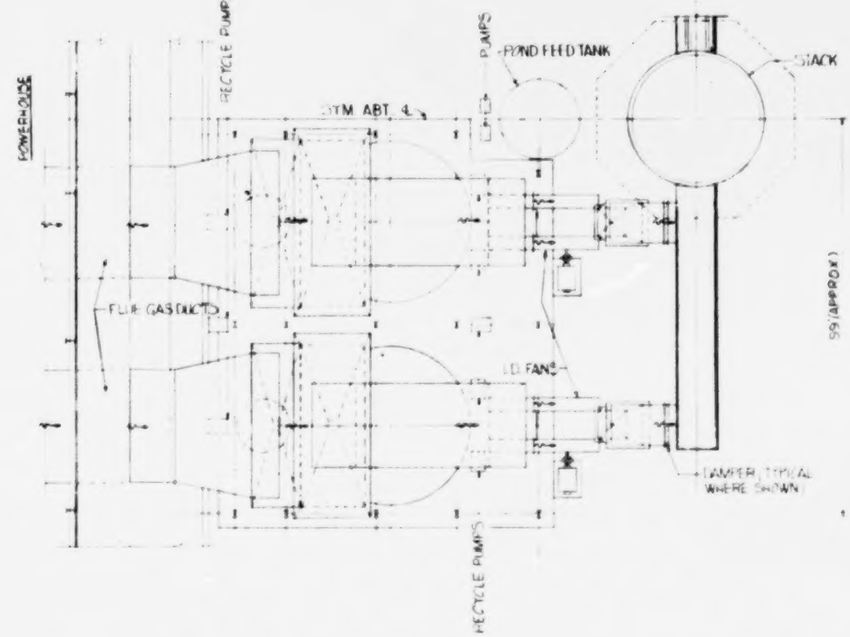
M — THOUSAND

Figure 1. Limestone slurry process. Flow diagram and material balance–base case.

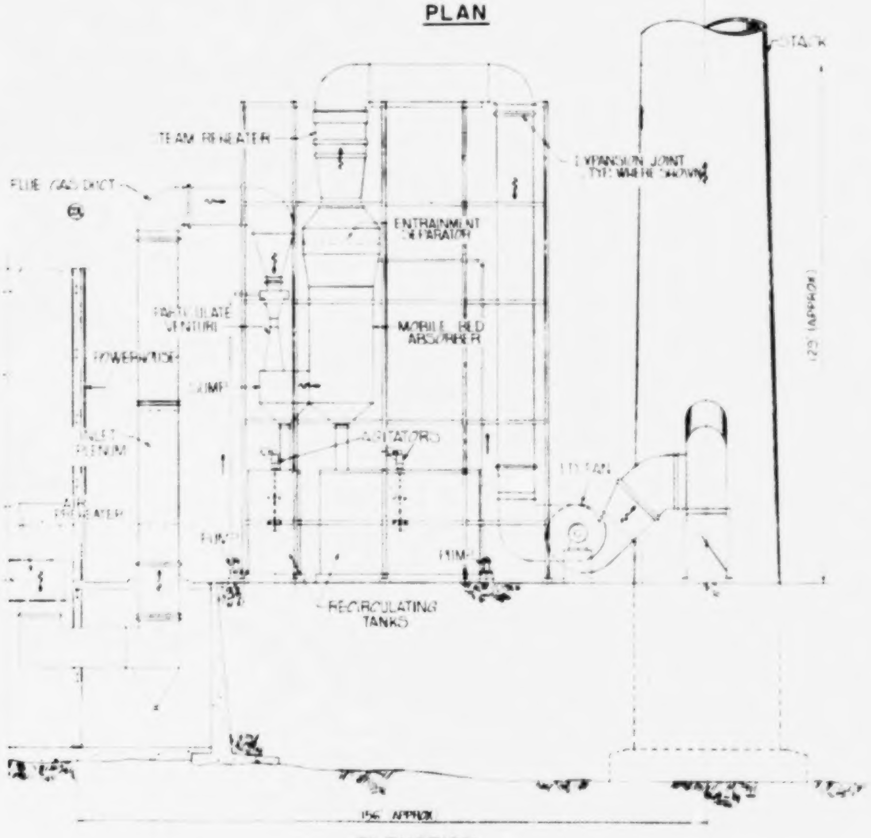

BOILER
PULVERIZED COAL
ECONOMIZER
AIR HEATER
AIR
EMERGENCY WATER
PARTICULATE SCRUBBER
SO_2 ABSORBER
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
VACUUM RELIEF
MAKE-UP WATER
FAN
STACK
POND WATER
AGITATOR
POND FEED TANK
PUMP
PS EFFLUENT HOLD TANK
SA EFFLUENT HOLD TANK
SETTLING POND
RAIL OR TRUCK
PILE
HOPPERS, FEEDERS & CONVEYORS
ELEVATOR
BIN
FEEDERS
WEIGH BELTS
GYRATORY CRUSHERS
ELEVATORS
WET BALL MILLS
MILLS PRODUCT TANK
SEAL WATER TYP FOR ALL
SLURRY FEED TANK
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

NOTE: STANDARD I.S.A. IDENTIFICATION LETTERS USED ON INSTRUMENTATION
SOOT BLOWER CONTROLS NOT SHOWN
a ONE ANALYZER WITH 4 ALTERNATE FEEDS
b ONE INTEGRATOR FOR 4 FLOWS

Figure 2. Limestone slurry process. Control diagram—base case.


POWERHOUSE
RECYCLE PUMPS
PUMPS
POND FEED TANK
STACK
SYM ABT. ℄
FLUE GAS DUCTS
I.D. FANS
DAMPER (TYPICAL WHERE SHOWN)
59'(APPROX.)
RECYCLE PUMPS

PLAN


STACK
STEAM REHEATER
EXPANSION JOINT (TYP. WHERE SHOWN)
FLUE GAS DUCT
℄
ENTRAINMENT SEPARATOR
PARTICULATE VENTURI
MOBILE BED ABSORBER
POWERHOUSE
SUMP
INLET PLENUM
AGITATORS
I.D. FAN
AIR PREHEATER
PUMP
PUMP
129' (APPROX.)
RECIRCULATING TANKS
156' APPROX.

ELEVATION

Figure 3. Limestone slurry process. Venturi and mobile bed scrubber system—plan and elevation—base case.

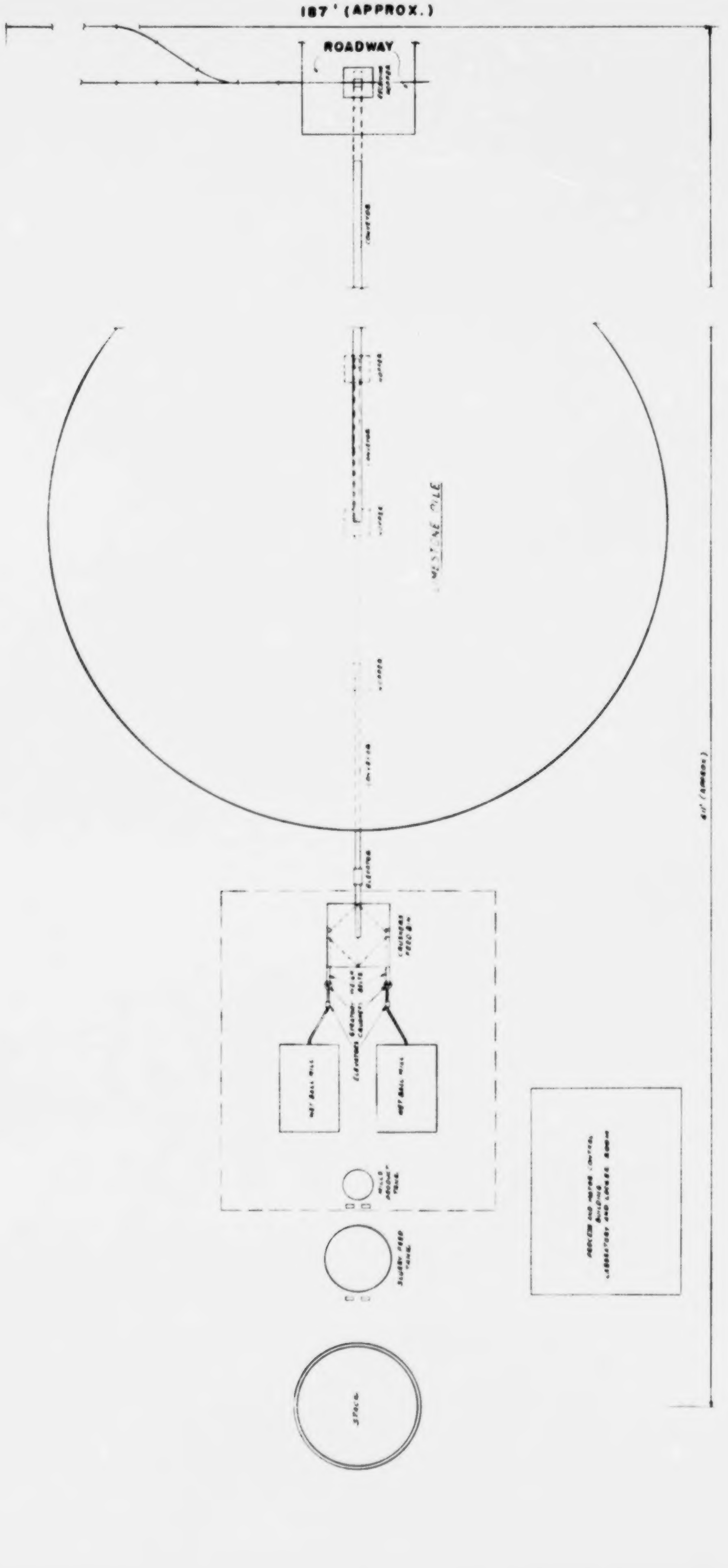

187' (APPROX.)
ROADWAY

Figure 4. Limestone slurry process. Materials handling and feed preparation system layout—plan—base case.

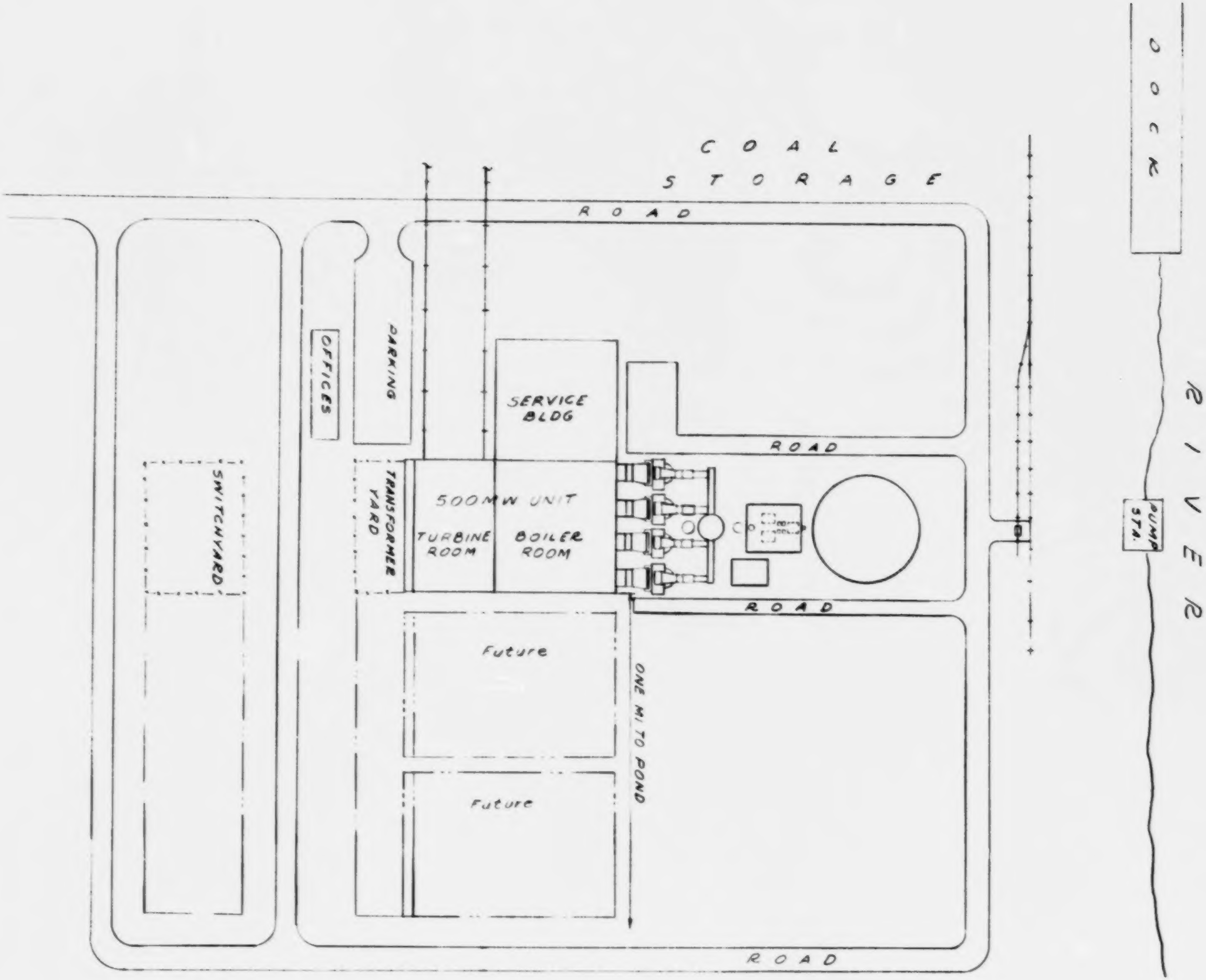

COAL STORAGE
DOCK
RIVER
PUMP STA.
ROAD
ROAD
ROAD
ROAD
PARKING
OFFICES
SERVICE BLDG
500MW UNIT
TURBINE ROOM
BOILER ROOM
TRANSFORMER YARD
SWITCHYARD
Future
Future
ONE MI. TO POND

Figure 5. Limestone slurry process. Overall plot plan—base case.

in-process limestone storage facilities upstream of the feed preparation area. The following equipment is provided:

1. One 94-ft^3-capacity limestone receiving hopper equipped with a 2.5-hp vibrator.
2. One 2.5-hp limestone vibratory feeder.
3. One 2.5-hp belt conveyor.
4. One 20-hp limestone stocking conveyor.
5. Three 65-ft^3 feed hoppers located beneath the pile, each equipped with 1-hp vibrating feeders.
6. One 3.0-hp conveyor under pile.
7. Two 5-gpm, 0.25-hp, rubber-lined tunnel sump pumps.
8. One 15-hp elevator to live storage area.
9. One 5,000-ft^3 twin-compartment limestone feed bin equipped with two 1-hp vibrators.
10. One railroad trackside vibrating car shaker.
11. One 2,000-cfm and one 6,000-cfm dust collecting system including inertial separators, cyclones, hoppers, fans, and drives.
12. One fabric dust collector designed to filter 14,000 cfm of gas (one-half the cost is included in this area; the other half is included in the feed preparation area).

Feed Preparation

This area includes the equipment for converting the raw limestone to a 70% -200 mesh, 60% solids slurry for feed to the scrubbers. The following equipment is provided:

1. Two parallel 1.5-hp limestone weigh feeders fed by 2 vibrating bin discharge feeders.
2. Two parallel 50% capacity, 25-hp gyratory crushers for reducing the stone size from -1-1/2 in. to -3/4 in.
3. Two parallel 1-hp elevators which discharge into the wet ball mills.
4. Two parallel 50% capacity, 450-hp wet ball mills for grinding the stone from -3/4 in. to 70% -200 mesh.
5. One 1,920-gal rubber-lined mills product tank equipped with baffles and a 1-hp rubber-coated agitator.
6. Two parallel (1 operating and 1 spare), 96-gpm, 3-hp rubber-lined centrifugal pumps.
7. One 46,080-gal rubber-lined slurry feed tank (providing for 8 hr of slurry storage) equipped with baffles and a 10-hp rubber-coated agitator.
8. Two parallel (1 operating and 1 spare), 96-gpm, 3-hp rubber-lined centrifugal pumps.
9. One 86-ft-long x 73-ft-wide x 30-ft-high building for housing the grinding facilities.
10. One 5-ton electric hoist.
11. One 8,000-cfm dust collecting system including an inertial separator, cyclone, 2 dust hoppers, fan, and drive.
12. One fabric dust collector designed to filter 14,000 cfm of gas (one-half of cost is included in this area; the other half is included in the materials handling area).

Particulate Scrubbers and Inlet Ducts

The following flue gas distribution and particulate scrubbing facilities for new coal-fired power units are included in this area:

1. Four flue gas ducts between the air heater discharge duct outside the powerhouse and the inlet flue gas plenum.
2. One inlet flue gas plenum interconnecting each of the 4 flue gas ducts.
3. Four flue gas ducts between the inlet plenum and the particulate scrubber, including 1 damper per duct.
4. Four 36-ft-long x 5-ft-wide x 20-ft-high rubber-lined venturi scrubbers equipped with variable throats.
5. Four 28-ft-long x 41-ft-wide x 13-ft-high rubber-lined sumps for distribution of flue gas from the venturi scrubbers to the mobile bed SO_2 absorbers (one-half of the cost is included in this area; the other half is included in the SO_2 scrubbing area).
6. Twenty soot blowers (5 per scrubber).
7. Four 25,700-gal, 13-ft-diameter x 26-ft-high open-top, rubber-lined carbon steel effluent hold tanks with four 5-hp rubber-coated agitators.
8. Six 4,900-gpm, 300-hp rubber-lined centrifugal slurry recirculation pumps (4 operating and 2 spares).

Existing coal-fired units are assumed to be equipped with 98.7% efficient electrostatic precipitators and do not require additional particulate scrubbing facilities. Fly ash emission from new and existing oil-fired power units does not exceed the EPA particulate emission standard; therefore, these units also do not require particulate removal facilities.

SO_2 Scrubbers and Ducts

The following equipment is provided:

1. Four 28-ft-long x 41-ft-wide x 13-ft-high rubber-lined sumps for distribution of flue gas from the venturi scrubber to the mobile bed SO_2 absorber (one-half of cost is included in this area; the other half is included in the particulate scrubbing area).
2. Four 41-ft-long x 13-ft-wide, x 41-ft-high two-bed, rubber-lined carbon steel mobile bed absorbers with stainless steel grids, high density polyethylene spheres, stainless steel chevron-type entrainment separators designed for upstream wash with fresh makeup water, and provisions for adding a future entrainment wash tray.
3. Forty soot blowers (10 per scrubber).
4. Four exit flue gas ducts between SO_2 scrubber outlet

and I.D. fan inlet. For existing units, flue gas ducts and inlet plenum between the outlet of the supplemental F.D. fan and the inlet to the stack gas plenum are included.

5. Four 240,000-gal, 40-ft-diameter x 26-ft-high open-top, rubber-lined carbon steel effluent hold tanks with four 50-hp rubber-coated agitators.
6. Ten 11,500-gpm, 500-hp, rubber-lined, centrifugal slurry recirculation pumps (8 operating and 2 spares).
7. Two 1,240-gpm, 100-hp vertical, multiple-stage turbine makeup water pumps (1 operating and 1 spare).

Stack Gas Reheat

This area includes facilities for reheating the gas to obtain an outlet stack gas temperature of 175°F.

New power units are designed with I.D. fans downstream of the scrubbers which discharge into the stack gas plenum; some of the reheat is obtained as the gas is compressed in passing through the fans. However, approximately 4°F of reheat are lost as the gas passes through the stack. The additional reheat required to obtain 175°F at the stack outlet is supplied by the stack gas reheat facilities. Fans for existing power units are located upstream of the scrubbers; therefore, all of the required reheat for existing systems must be obtained from the stack gas reheat facilities. Since the saturation temperature for coal- and oil-fired systems is different, and the pressure and temperature increase in passing through the fan varies with coal- and oil-fired systems, different amounts of reheat are required for each design. Table 15 shows the temperature increase in degrees Fahrenheit required to obtain an exit temperature of 175°F at the stack outlet.

A new 500-MW coal-fired power unit is designed with four 2,028-ft^2 indirect steam (500 psig) tube-type heat exchangers (one per duct) constructed within the exit flue gas ducts upstream of the fan. One-half of the tubes (scrubber side) are Inconel 625 and the other half (fan side) are Cor-Ten. Twenty soot blowers are provided (5 per reheater) for periodic cleaning of the tubes. Existing coal-fired units and new and existing oil-fired units are designed with one direct oil-fired reheater per duct which discharges hot combustion gases directly into the duct.

Fans

A new balanced-draft coal-fired power unit without pollution control facilities normally requires one I.D. fan per duct capable of overcoming a pressure drop of 15 inches downstream of the boiler. The increased pressure drop resulting from the addition of stack gas scrubbing facilities to the power unit varies with power unit type (coal- or oil-fired), plant status (new or existing), and process design. This additional energy is supplied by the installation of either greater capacity fans for new units or supplemental fans for existing units. For new power units, the investment and operating cost attributed to the scrubbing facilities are estimated as the difference between the investment or operating costs of the higher energy fans in comparison with a 15-inch capacity fan. For existing power units, the total investment and operating cost of the additional fans are included. Table 16 identifies the pressure drop distribution provided for each of the various system designs.

The cost for a plenum to the stack is not included in the investment estimate; it has been assumed that this equipment is required by the power unit. The following are included in the base case investment and operating cost estimates:

1. Incremental costs for four 3,250-hp (41 in. △ P) induced draft fans prorated for 26 inches of pressure drop attributed to particulate and SO_2 removal.
2. Four exit flue gas ducts between the I.D. fans and the stack gas plenum.

The new fans provided for existing power units are located adjacent to and in series with the existing I.D. fans. The costs for this area include the ductwork between the tie-in to the existing duct and the inlet of the fan.

Table 15. Flue Gas Reheat Requirements–Limestone Slurry Process

Power unit		Required temperature increase, °F
Type	Status	
Coal fired	New	38
Coal fired	Existing	53
Oil fired	New	34
Oil fired	Existing	46

Table 16. Assumed Pressure Drop Distribution for Specification of Fans–Limestone Slurry Process

Power unit			Pressure drop distribution, inches H_2O attributed to		
Fuel	Status	SO_2 removal efficiency, %	Power production	Gas cleaning	Total
Coal	New	90	15.0	26.0[b]	41.0
Coal	Existing	90	–[a]	21.0	21.0
Oil	New	90	15.0	19.0	34.0
Oil	Existing	90	–[a]	21.0	21.0
Coal	New	80	15.0	24.0[b]	39.0
Coal	Existing (requiring particulate scrubber)	90	–[a]	28.0[b]	28.0

[a] Existing power units already have fans which overcome the pressure drop attributed to power production.

[b] Includes pressure drop attributed to both particulate and SO_2 removal.

Calcium Solids Disposal

For new coal-fired power units utilizing on-site solids disposal, the solids disposal area is designed for both fly ash and calcium solids disposal in a single pond. For consistent comparison of processes, however, the costs associated with fly ash disposal are excluded from the estimate. The costs for the solids disposal pumps, disposal line to the pond, pond, pond liner, and pond water return pumps and piping are prorated using a 0.637 factor which is the fraction of calcium solids in the calcium - fly ash mixture to be disposed; only the portion of costs attributed to calcium solids disposal is included in the estimates. Existing coal-fired power units and both new and existing oil-fired units require a single pond for disposal of calcium solids only. The following items are included in the base case estimate:

1. One 63,000-gal, 21-ft-diameter x 26-ft-high rubber-lined open-top tank (sized with a liquid holdup capacity equivalent to the total liquid holdup in the particulate and SO_2 scrubbers) with a 7.5-hp rubber-coated agitator.
2. Prorated cost for four 1,130-gpm, 50-hp rubber-lined pond feed pumps (2 in series operating and 2 in series spare).
3. Prorated cost for 1 rubber-lined solids disposal line to pond (~1 mile).
4. Prorated cost for one 40-ft-deep, 206-acre clay-lined disposal pond with concrete sump; lifetime pond capacity - 127,500 operating hr; 131.0 acres are attributed to calcium solids disposal. Lifetime pond capacities for existing 200-MW units are equivalent to 57,500 operating hr; the 500- and 1,000-MW existing units have disposal ponds with capacities equivalent to 92,500 operating hr.
5. Prorated cost for two 1,000-gpm, 75-hp carbon steel recycle pond water pumps with stainless steel impellers.
6. Prorated cost for 1 carbon steel pond water return line.

For off-site solids disposal, the following items are provided:

1. One 63,000-gal 21-ft-diameter x 26-ft-high rubber-lined open-top tank with a 7.5-hp rubber-coated agitator.
2. Prorated cost for two 1,000-gpm, 25-hp rubber-lined carbon steel thickener feed pumps (1 operating and 1 spare).
3. Prorated cost for two 140-ft-diameter x 16-ft 8-in.-high rubber-lined thickener tanks with thickener rakes, supports, and drive.
4. Prorated cost for one 1,920-gal thickener overflow receiving tank.
5. Prorated cost for two 566-gpm, 10-hp carbon steel overflow return pumps (1 operating and 1 spare).
6. Prorated cost for three 210-gpm, 3-hp rubber-lined thickener underflow pumps (2 operating and 1 spare).
7. Prorated cost for 2 rotary vacuum filters 12-ft-diameter x 18-ft-long, equipped with 150-hp vacuum pumps, filtrate receiver, and 10-hp filtrate recycle pumps.
8. Prorated cost for one 1-hp horizontal belt conveyor.
9. Prorated cost for one 10-hp inclined belt conveyor.
10. Prorated cost for one 21,200-ft^3 cake loading silo equipped with bin vibrators.

Utilities

The availability of certain utilities (steam, water, and electricity) to the pollution abatement facilities is dependent upon the power plant status (new vs. existing). For utilities which may be obtained from the power plant, investment costs for distribution to the processing area are included and the utility price consists of all actual production costs including capital charges. For utilities which cannot be obtained from the power plant, the total investment and operating cost for generation and distribution is included. The investment estimate includes cost for the following:

1. One instrument air supply system including air compressor, air dryer, and air header to the process control equipment.
2. One 500-psig steam supply system from the boiler to the indirect steam reheat facilities, including steam header, and condensate return piping to the boiler feed water system. Existing coal-fired and both new and existing oil-fired units are designed with a direct fuel oil-fired reheat and fuel oil supply system, including 1 fuel oil unloading station, 1 storage tank, 2 fuel oil feed pumps, and insulated piping above ground between the feed pumps and the oil-fired reheat system.
3. Allocation for fire and service water supply to the processing area including area piping.
4. Process water supply header from condenser discharge sump to the scrubbing facilities.
5. Electrical facilities including 200 ft of feeder cable and conduit from the power plant to the processing area. The investment for existing units includes costs for a new transformer and approximately 900 ft of feeder cable and conduit from the switchyard to the processing area.
6. Sanitary and storm sewers including approximately 250 ft of 24-in. vitrified clay pipe.

Service Facilities

Costs for the following items are included in this area:

1. Vehicles—1 gasoline-powered, 2-yd^3-capacity payloader, and allocation to power unit for use of plant vehicles.
2. Buildings and equipment—one 5,000-ft^2 maintenance and instrument shop; one 2,200-ft^2 building, including process and motor control facilities, laboratory, lockers, offices, and restrooms; allocation to power unit for one 2,000-ft^2 stores area.
3. Railroads—costs for ½ mile of track, 3 switches, and 2 car pullers.
4. Parking lot, walkways, and approximately 1 mile of paved roads.
5. Landscaping, fencing, and security.

Units with direct oil-fired reheat systems include an additional 800 feet of railroad and 2 switches in this area for fuel oil receiving and handling.

Construction Facilities

Based on TVA experience, the costs for temporary facilities required during construction are projected as 5% of the subtotal area investments to include projected costs for the various craft sheds, temporary offices, and restroom facilities.

LIME SLURRY PROCESS

The lime slurry process removes SO_2 from power plant stack gas by contacting the gas with a recirculating slurry stream containing slaked lime and reaction products in two venturi absorbers in series for each parallel gas train. The incoming pebble lime, from an "across the fence" limestone calcination plant, is received in bins sized for 5 days' storage and conveyed to an 8-hour process bin which serves as supply to the slakers. The lime is slaked in two parallel slakers at a slurry concentration of 25% solids and subsequently diluted with pond water to 15% solids. A slurry feed tank with a residence time of 8 hours is provided for in-process storage.

Approximately 78% of the lime slurry is fed to the first-stage venturi scrubbers where the fly ash and 70% of the SO_2 is removed. The remaining portion of the slaked lime slurry is fed along with recycle pond water to the recirculation loops for the second-stage SO_2 absorbers. These absorbers are equipped with chevron-type entrainment separators designed for upstream wash with fresh makeup water. Approximately 70% of the remaining SO_2 in the gas is removed in the second-stage absorbers. To achieve the required SO_2 removal efficiency, two venturi absorber stages are also utilized to remove SO_2 for existing coal-fired and both new and existing oil-fired units which do not require fly ash removal facilities. In every case, reacted slurry from the second-stage venturi scrubbing loop is fed to the first-stage venturi scrubbing loop.

The spent slurry consisting of calcium compounds and fly ash for new coal-fired units is pumped to the pond where it settles to about a 40% solids slurry. Pond water is recycled to the lime slakers and venturi scrubbing loops. A special case in which the calcium compounds and fly ash from new coal-fired units are trucked to and disposed of off-site is evaluated similar to the limestone slurry process. The total land requirement for the base case lime slurry process is broken down as follows:

Process function	Land required, acre
Fly ash and SO_2 removal	5.5
Waste disposal	
Fly ash	75.0
Calcium solids	113.0

Excluding the disposal area required for fly ash as discussed in the premises, the total amount of land included in the lime slurry process cost estimate is 118.5 acres. The flow diagram, material balance, control diagram, plot plan, process layouts, and elevation drawing are shown in figures 6-10 for the base case, followed by the area-by-area process equipment descriptions.

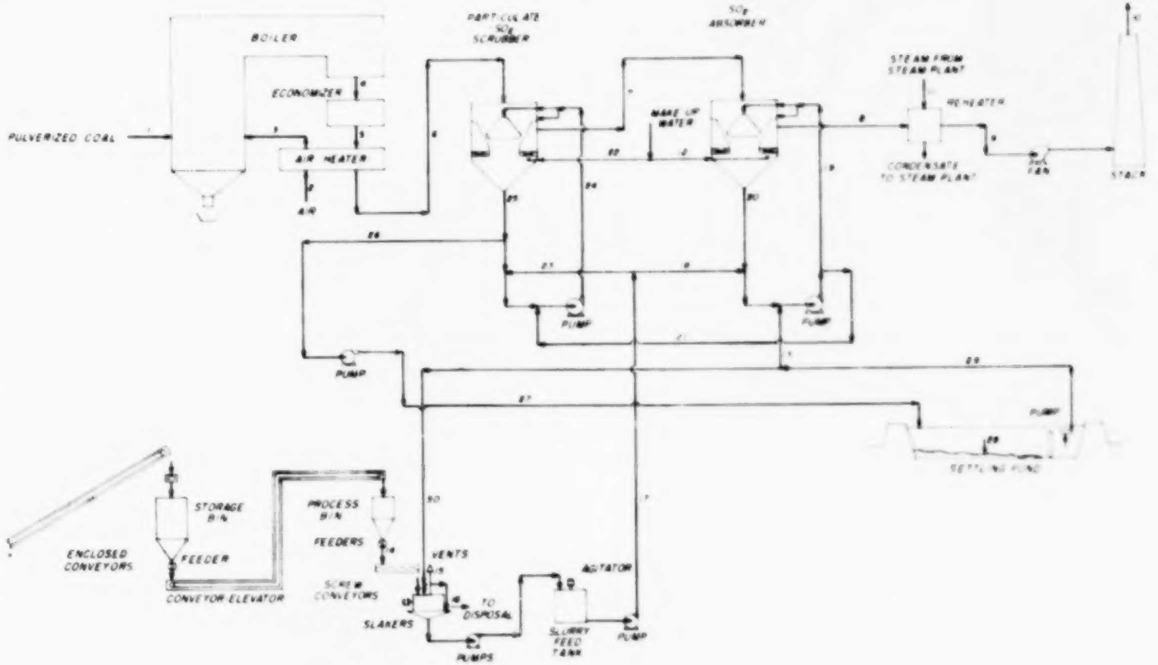
Lime Receiving and Storage

This area includes facilities for receiving pebble lime from an "across the fence" limestone calcination plant, storage in bins for 5 days, and live in-process storage for supply to the slakers. The following equipment is provided:

1. One 15-hp enclosed belt conveyor.
2. One 7.5-hp enclosed belt conveyor.
3. Four 11,800-ft^3-capacity lime storage bins equipped with 16 bin vibrators.
4. Four storage bin discharge feeders (rotary air lock type).
5. One 5-hp conveyor-elevator between the storage bins and the process bin.
6. One 4,320-ft^3-capacity process bin equipped with 8 bin vibrators.
7. Two process bin discharge feeders (rotary air lock type).

Feed Preparation

The pebble lime is slaked as a 25% solids slurry in two parallel slaking systems and diluted with pond water to a 15% solids slurry. In-process storage is provided before feeding the slurry to the absorption system. The following equipment is provided:


PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
PARTICULATE SO2 SCRUBBER
SO2 ABSORBER
MAKE UP WATER
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
FAN
STACK
PUMP
PUMP
PUMP
PUMP
SETTLING POND
ENCLOSED CONVEYORS
STORAGE BIN
FEEDER
CONVEYOR ELEVATOR
PROCESS BIN
FEEDERS
SCREW CONVEYORS
VENTS
SLAKERS
TO DISPOSAL
PUMPS
AGITATOR
SLURRY FEED TANK
PUMP

STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO PRT. SO2 SCRUBBER	GAS TO SO2 ABSORBER	GAS TO REHEATER	GAS TO FAN	GAS TO ATMOSPHERE	STEAM TO GAS REHEATER	MAKE UP WATER TO SO2 ABSORBER	POND WATER TO SO2 ABSORBER	LIME TO SCREW CONVEYOR	VENT FROM SLAKER	GRIT TO DISPOSAL	LIME SLURRY TO SYSTEM	LIME SLURRY TO SO2 ABSORBER	RECYCLE SLURRY TO SO2 ABSORBER	DISCHARGE SLURRY FROM SO2 ABSORBER
RATE, LBS/HR	379M	[illegible]	4,079M	4,404M	4,404M	1,122M	1,290M	1,298M	1,298M	5,192M	179M	39.8M	32.6	[illegible]	[illegible]	5	20.1M	2M	6,695M	6,730M
SCFM		984M	888M	943M	947M	260M	280M	288M	288M	[illegible]										
GPM												79.7	[illegible]				370	20.5	3.0M	3.1M
PARTICULATES, LBS/HR				337M	33.7M	8,435	55.8	55.8	55.8	223										
TEMPERATURE, °F		110	535	880	725	310	125	125	165	175	470						125			
SPECIFIC GRAVITY																	1.09			
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %																	5			
pH												SEE NOTE 5								

STREAM NO	21	22	23	24	25	26	27	28	29	30
DESCRIPTION	SO2 ABSORBER SLURRY TO PRT. SO2 SCBR.	MAKE UP WATER TO PRT. SO2 SCBR.	LIME SLURRY TO PRT. SO2 SCBR.	RECYCLE SLURRY TO PRT. SO2 SCBR.	DISCHARGE SLURRY FROM PRT. SO2 SCBR.	USED SLURRY & FLY ASH TO PUMP	USED SLURRY & FLY ASH TO STLG. POND	SETTLED USED SLURRY & FLY ASH	RECYCLE POND WATER	POND WATER TO SLAKER
RATE, LBS/HR	55.4M	398M	39.2M	7,430M	7,459M	95.4M	382M	209M	193M	90M
SCFM										
GPM	108	797	71.9	13.0M	13.0M	187	688	319	386	180
PARTICULATES, LBS/HR										
TEMPERATURE, °F										
SPECIFIC GRAVITY	1.05					1.14		1.51		
VISCOSITY, CPS										
UNDISSOLVED SOLIDS, %	5					22		40		
pH		SEE NOTE 5				~7.9		SEE NOTE 5	SEE NOTE 5	

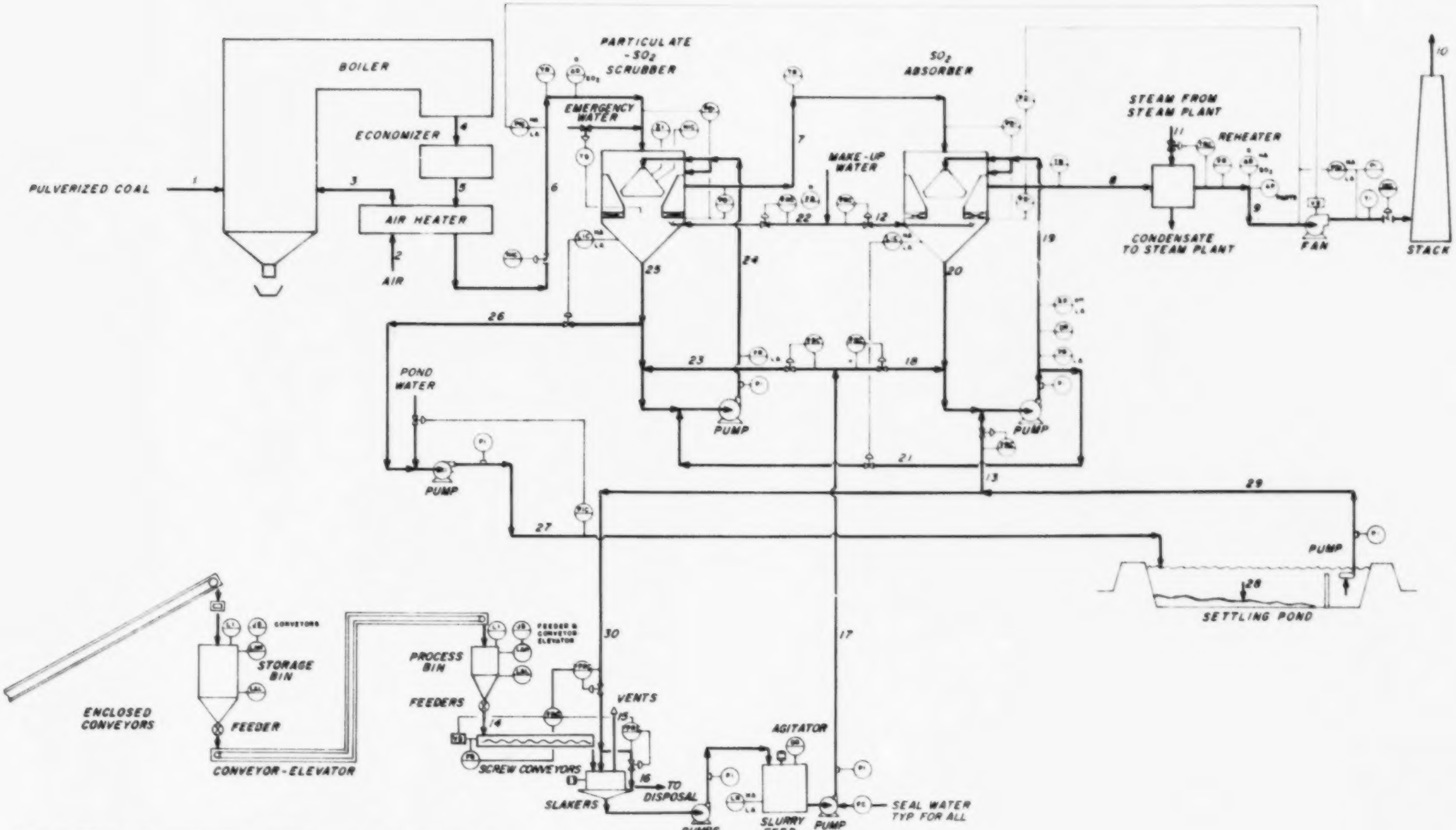
NOTES

1. CALCULATIONS BASED ON
   - a. 110% STOICHIOMETRIC LIME, 95% CaO
   - b. 3.0% SULFUR IN COAL (DRY)
   - c. 12% ASH COAL (AS FIRED)
   - d. 92% OF SULFUR IN COAL EVOLVES AS SO_2
   - e. 75% OF ASH IN COAL EVOLVES AS FLY ASH
   - f. 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
   - g. 90% SO_2 REMOVAL
   - h. POND EVAPORATION EQUAL TO RAINFALL
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS 6-9, 11-13 & 18-20 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 14-16 & 30 ARE ONE OF TWO SIMILAR STREAMS
5. RATES FOR LINES 12, 22, 28 & 29 ASSUME ABOUT ONE-SIXTH OF POND LIKE SETTLED SOLIDS INTERSTITIAL H_2O IS PUT INTO POND FOR STARTUP

SYMBOL IN TABLE

M THOUSAND

Figure 6. Lime slurry process. Flow diagram and material balance–base case.

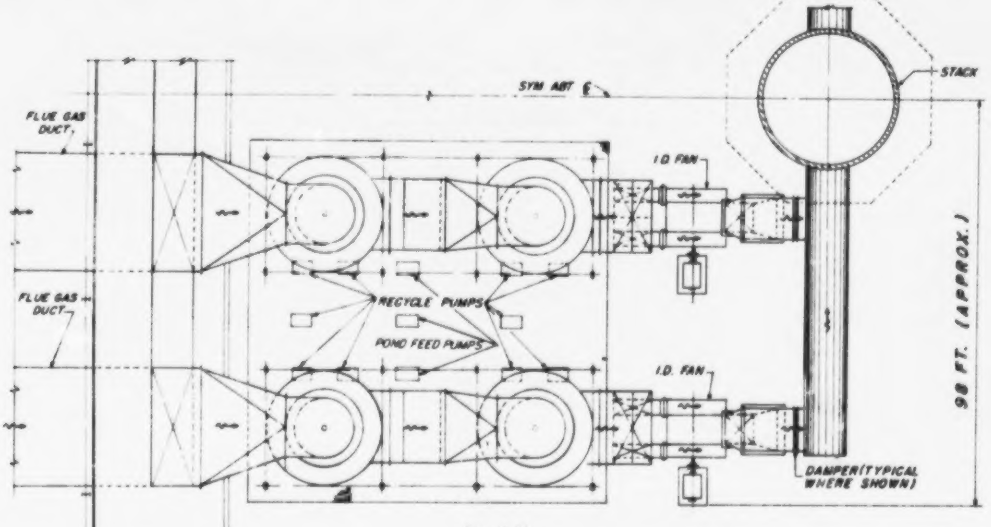

PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
PARTICULATE -SO2 SCRUBBER
EMERGENCY WATER
MAKE-UP WATER
SO2 ABSORBER
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
FAN
STACK
POND WATER
PUMP
SETTLING POND
ENCLOSED CONVEYORS
STORAGE BIN
FEEDER
CONVEYOR-ELEVATOR
PROCESS BIN
FEEDERS
SCREW CONVEYORS
VENTS
SLAKERS
TO DISPOSAL
PUMPS
AGITATOR
SLURRY FEED TANK
SEAL WATER TYP FOR ALL
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30

NOTE STANDARD I S A IDENTIFICATION LETTERS USED ON INSTRUMENTATION, SOOT BLOWER CONTROLS NOT SHOWN

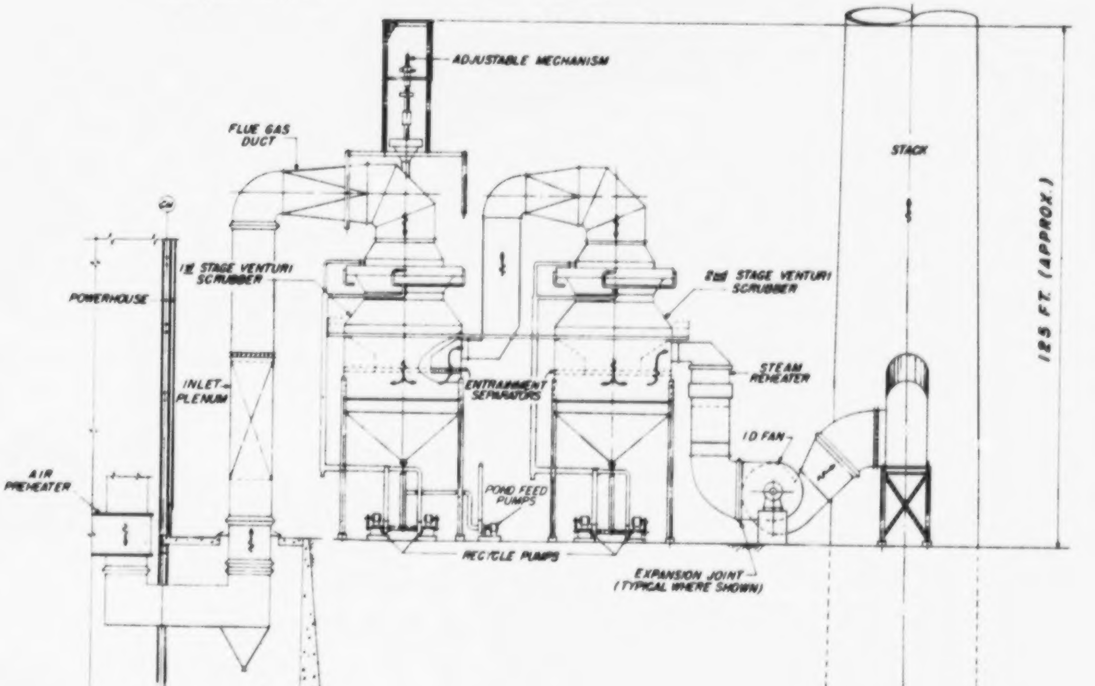
a ONE ANALYZER WITH 4 ALTERNATE FEEDS

b ONE INTEGRATOR FOR 8 FLOWS

Figure 7. Lime slurry process. Control diagram–base case.


SYM ABT ℄
STACK
FLUE GAS DUCT
I.D. FAN
FLUE GAS DUCT
RECYCLE PUMPS
POND FEED PUMPS
I.D. FAN
DAMPER (TYPICAL WHERE SHOWN)
98 FT. (APPROX.)

PLAN


ADJUSTABLE MECHANISM
FLUE GAS DUCT
STACK
POWERHOUSE
1st STAGE VENTURI SCRUBBER
2nd STAGE VENTURI SCRUBBER
INLET PLENUM
ENTRAINMENT SEPARATORS
STEAM REHEATER
I.D. FAN
AIR PREHEATER
POND FEED PUMPS
RECYCLE PUMPS
EXPANSION JOINT (TYPICAL WHERE SHOWN)
125 FT. (APPROX.)
177 FT (APPROX)

ELEVATION

Figure 8. Lime slurry process. Two-stage venturi scrubber system—plan and elevation—base case.

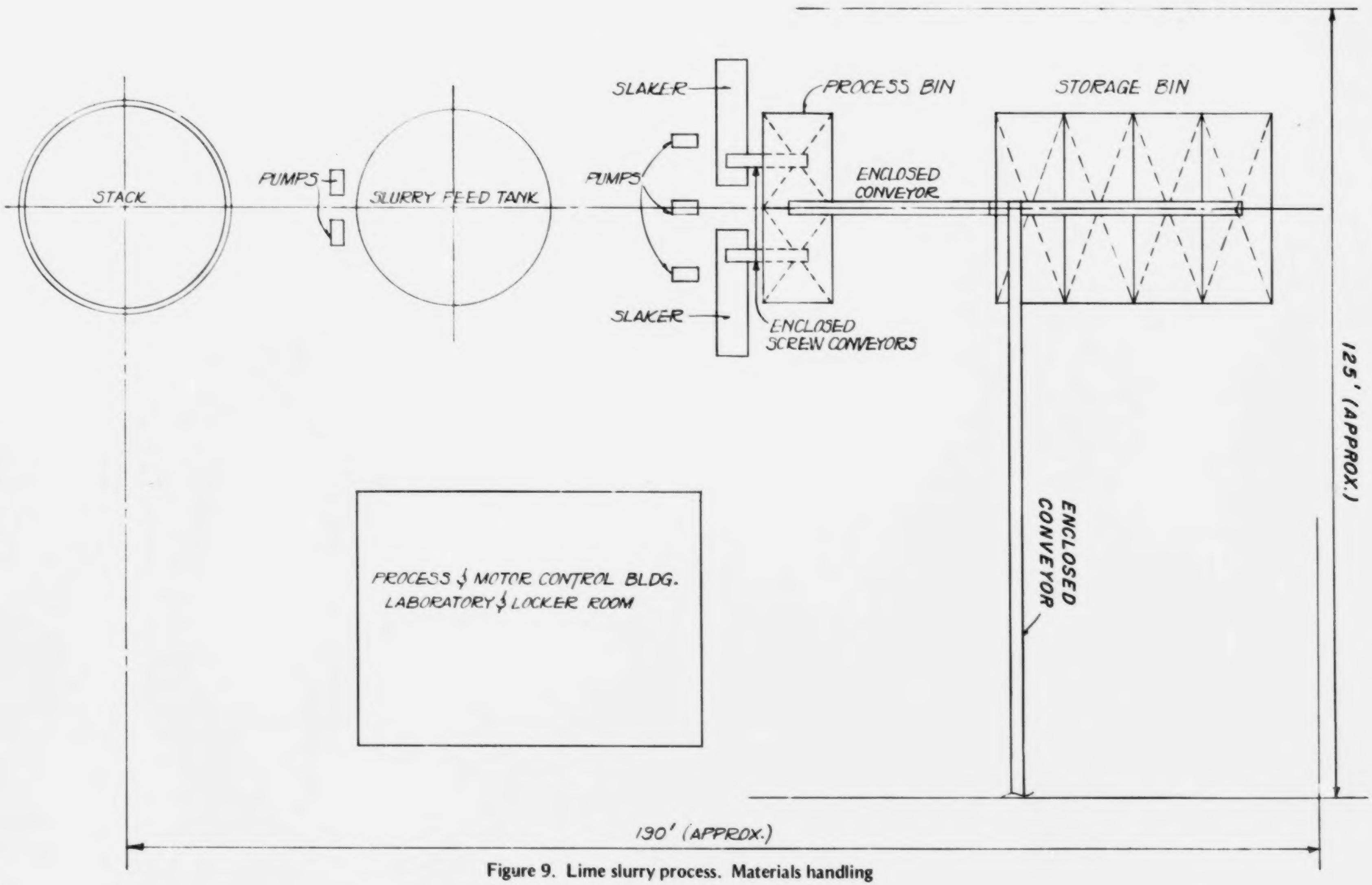

SLAKER
PROCESS BIN
STORAGE BIN
PUMPS
STACK
SLURRY FEED TANK
PUMPS
ENCLOSED CONVEYOR
SLAKER
ENCLOSED SCREW CONVEYORS
125' (APPROX.)
PROCESS $ MOTOR CONTROL BLDG.
LABORATORY $ LOCKER ROOM
ENCLOSED CONVEYOR
130' (APPROX.)

Figure 9. Lime slurry process. Materials handling and feed preparation system layout–plan–base case.

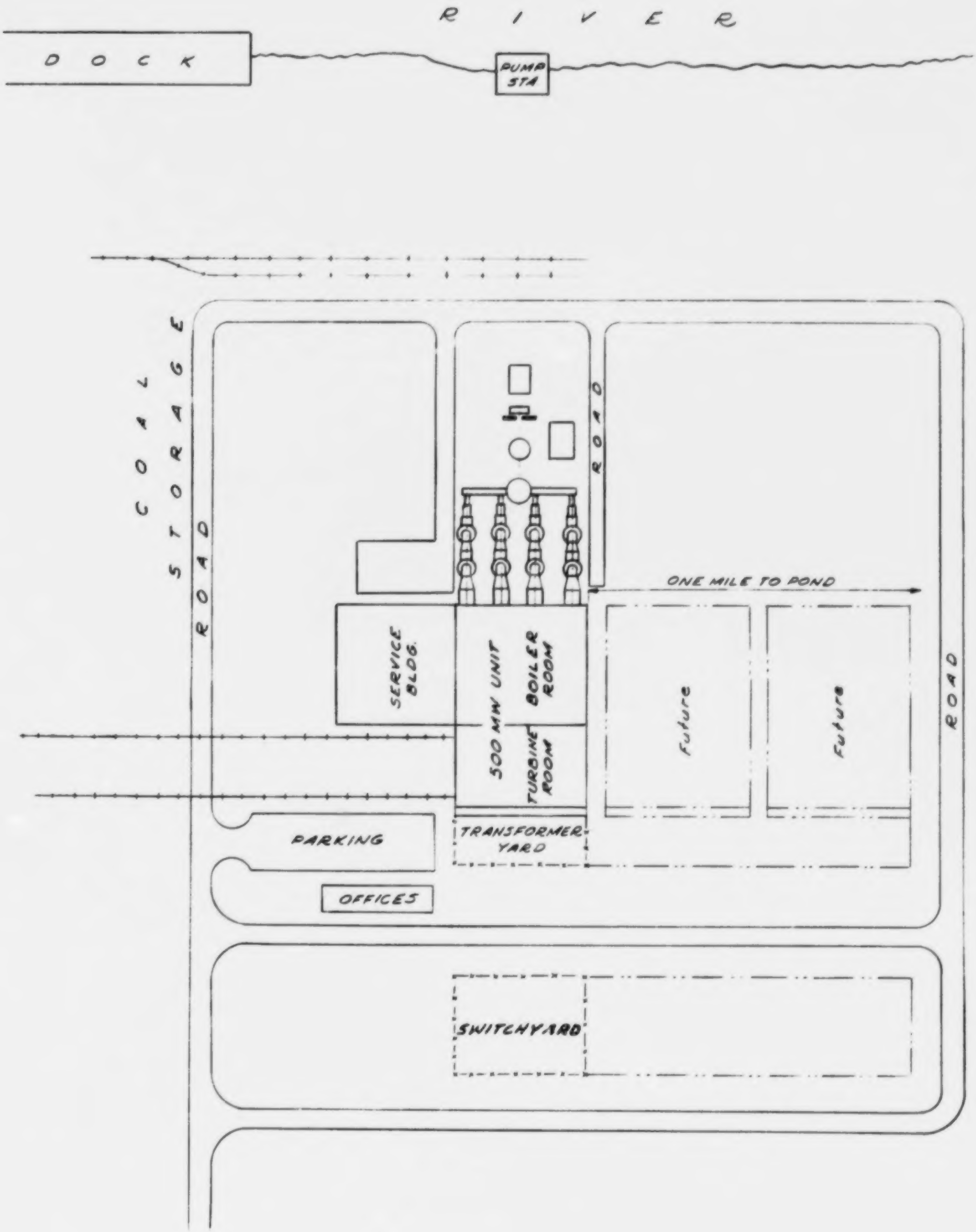

RIVER
DOCK
PUMP STA
COAL STORAGE
ROAD
ROAD
ONE MILE TO POND
SERVICE BLDG.
500 MW UNIT
BOILER ROOM
TURBINE ROOM
Future
Future
ROAD
TRANSFORMER YARD
PARKING
OFFICES
SWITCHYARD

Figure 10. Lime slurry process. Overall plot plan—base case.

1. Two 1-hp screw conveyors.
2. Two parallel 11,600 lb/hr slakers, 20-ft-long x 5.5-ft-wide x 9-ft-high.
3. Three parallel (2 operating and 1 spare), 185-gpm, 5-hp rubber-lined centrifugal pumps.
4. One 177,600-gal rubber-lined slurry feed tank (providing for 8 hr of slurry storage) equipped with baffles and a 15-hp rubber-coated agitator.
5. Two parallel (1 operating and 1 spare) 370-gpm, 5-hp rubber-lined centrifugal pumps.

Particulate - SO_2 Scrubbers and Inlet Ducts

The lime slurry process requires a two-stage venturi absorption system with approximately 70% of the SO_2 removed in the first-stage venturi and approximately 70% of the remaining SO_2 removed in the second stage. The following facilities for distribution of flue gas and removal of particulates and SO_2 are included in this area:

1. Four flue gas ducts between the air heater discharge duct outside the powerhouse and the inlet flue gas plenum. For existing units, flue gas ducts between the supplemental F.D. fan and the inlet flue gas plenum are included.
2. One inlet flue gas plenum interconnecting each of the four flue gas ducts.
3. Four flue gas ducts between the inlet plenum and the particulate scrubber, including one damper per duct.
4. Four 28-ft-diameter x 54.5-ft-high rubber-lined venturi scrubbers equipped with variable throats and stainless steel chevron-type entrainment separators designed for upstream wash with fresh makeup water.
5. Four flue gas ducts between the particulate - SO_2 scrubbers and the SO_2 absorbers (one-half of the cost is included in this area; the other half is included in the SO_2 scrubbing area).
6. Ten 6,500-gpm, 350-hp rubber-lined centrifugal slurry recirculation pumps (8 operating and 2 spare).
7. Two 660-gpm, 50-hp vertical, multiple-stage turbine makeup water pumps (1 operating and 1 spare; one-half of the cost is included in this area; the other half is included in the SO_2 scrubbing area).
8. Twenty soot blowers (5 per scrubber).

As previously stated, existing coal-fired units are assumed to be equipped with 98.7% efficient electrostatic precipitators. Although existing coal-fired units and both new and existing oil-fired units do not require the first-stage scrubber to remove fly ash, it is required for removal of SO_2.

Table 17. Flue Gas Reheat Requirements—Lime Slurry Process

Power unit		Required temperature
Type	Status	increase, °F
Coal fired	New	38
Coal fired	Existing	54
Oil fired	New	33
Oil fired	Existing	47

SO_2 Scrubbers and Ducts

Costs for the second stage of the two-stage venturi SO_2 removal system are included in this area. This scrubber and process equipment are similar to the first stage with the exception that a variable throat is not provided for the venturi. The following facilities for the distribution of flue gas are included:

1. Four flue gas ducts between the particulate - SO_2 scrubbers and the SO_2 absorbers (one-half of the cost is included in this area; the other half is included in the particulate - SO_2 scrubbing area).
2. Four exit flue gas ducts between the SO_2 scrubber outlet and I.D. fan inlet. For existing units, flue gas ducts between the SO_2 scrubber outlet and the inlet to the stack gas plenum are included.

Stack Gas Reheat

The reheat area includes facilities for reheating the gas to obtain an outlet stack gas temperature of 175°F. This system is similar to the reheat system described for the limestone slurry process. Table 17 shows the temperature increase in degrees Fahrenheit required to obtain an exit temperature of 175°F at the stack outlet.

Fans

Fan location, method of costing, and duct configuration in the lime and limestone slurry processes are similar with the exception of pressure drop. Table 18 identifies the pressure drop distribution provided for each of the various system designs.

Calcium Solids Disposal

For new coal-fired power units utilizing on-site solids disposal, the solids disposal area is designed for both fly ash and calcium solids disposal. However, investment costs for disposal of fly ash are excluded from the estimate similar to the method of costing described for the limestone slurry process. A prorate factor of 0.60 corresponds to the fraction of calcium solids in the calcium - fly ash mixture to be disposed. Existing coal-fired power units and both new

Table 18. Assumed Pressure Drop Distribution for Specification of Fans—Lime Slurry Process

Power unit			Pressure drop distribution, inches H_2O attributed to		
Fuel	Status	SO_2 removal efficiency, %	Power production	SO_2 removal	Total
Coal	New	90	15.0	26.0[b]	41.0
Coal	Existing	90	—[a]	22.0	22.0
Oil	New	90	15.0	20.0	35.0
Oil	Existing	90	—[a]	22.0	22.0
Coal	New	80	15.0	24.5[b]	39.5
Coal	Existing (requiring particulate scrubber)	90	—[a]	26.0[b]	26.0

[a] Existing power units already have fans which overcome the pressure drop attributed to power production.

[b] Includes pressure drop attributed to both particulate and SO_2 removal.

and existing oil-fired units require a disposal system for calcium solids only. The following equipment is included in the base case estimate:

1. Prorated cost for six 167-gpm, 15-hp rubber-lined centrifugal pond feed pumps (4 operating and 2 spare).
2. Prorated cost for 1 rubber-lined solids disposal line to pond (~1 mile).
3. Prorated cost for one 40-ft-deep, 188-acre clay-lined disposal pond; lifetime pond capacity—127.500 operating hr; 113.0 acres are attributed to calcium solids disposal. Lifetime pond capacity for existing 200-MW units are equivalent to 57.500 operating hr; the 500- and 1.000-MW existing units have disposal ponds with capacities equivalent to 92.500 operating hr.
4. Prorated cost for two 670-gpm, 50-hp carbon steel recycle pond water pumps with stainless steel impellers.
5. Prorated cost for 1 carbon steel pond water return line.

For off-site solids disposal, the equipment required is similar to that described for off-site disposal with the limestone process, except somewhat smaller in size. Only the portion attributed to calcium solids disposal is included in the estimate.

Utilities

The utilities area for the lime and limestone slurry processes are similar. A list of the equipment included in the estimate is given in the limestone slurry process utilities area description.

Service Facilities

This area includes costs for the following items:

1. Vehicles—allocation to power unit for use of plant vehicles.
2. Buildings and equipment—one 5,000-ft^2 maintenance and instrument shop; one 2,200-ft^2 building, including process and motor control facilities, laboratory, lockers, offices, and restrooms; allocation to power unit for one 2,000-ft^2 stores area.
3. Railroads—costs for 1,100-ft of track, 1 switch, and 1 car puller.
4. Parking lot, walkways, and approximately 1 mile of paved roads.
5. Landscaping, fencing, and security.

Units with direct oil-fired reheat systems include an additional 800 feet of railroad track and two switches in this area for fuel oil receiving and handling.

Construction Facilities

Construction facilities are projected as 5% of the subtotal area investments similar to the method used for the limestone slurry process.

MAGNESIA - SLURRY REGENERATION

In the magnesia slurry - regeneration process, fly ash is removed by wet scrubbing flue gas in a venturi by contact with a slurry of fly ash in water; SO_2 is absorbed in a separate venturi scrubber utilizing magnesium oxide as the absorbent. Magnesium sulfite formed in the SO_2 absorber is thermally regenerated to MgO, combined with required makeup MgO and recycled to the SO_2 absorber. The amount of makeup MgO is assumed to be approximately 2% per cycle. Fresh makeup MgO is unloaded from covered hopper cars by a pneumatic conveying system and stored in a bin before being fed to a slurry tank. Here the makeup MgO and regenerated MgO are slurried into a bleed stream of recycle liquor from the SO_2 absorber and recycled to the SO_2 absorption area. The particulate scrubber is designed to operate closed loop utilizing a recycle pond water—fly ash slurry as the scrubbing media. Humidification losses are added as fresh makeup water; this water is added as an upstream wash for the chevron-type entrainment separator in each of the SO_2 absorbers. The fly ash slurry is neutralized with slaked lime as required and pumped to the power plant ash disposal pond.

Effluent from the SO_2 absorber, containing approximately 10% solids, is passed through wet screens for thickening to a 40% solids slurry. The $MgSO_3 \cdot 6H_2O$ in the slurry is thermally converted to $MgSO_3 \cdot 3H_2O$ and pumped to two parallel centrifuges for separation of the solids from the liquor. The centrate and underflow from the wet screens are collected in a liquor tank, and returned to the slurry preparation area and the SO_2 absorber loop in the proper proportions.

The centrifuge cakes are dried in an oil-fired single-stage fluid bed dryer and the dryer off-gas is cleaned in a cyclone and fabric dust collector. A portion of the gas is recycled to the dryer combustion chamber for temperature control, and the remainder is exhausted to the stack gas plenum for reheat.

The $MgSO_3$ solids discharged from the dryer, cyclone, and bag filter are transferred to an in-process storage bin and fed to an oil-fired fluid bed calciner which contains a single calcination bed designed to operate at 1600°F and two air preheat-product cooling stages. The $MgSO_3$ is calcined in the presence of coke to generate MgO and SO_2 by direct combustion of fuel oil in the upper stage. The MgO is drawn from the lower cooling stage at a temperature of 225°F and fed to the slurry preparation area.

The off-gas from the calciner containing SO_2 is partially cleaned in a cyclone, cooled to about 700°F in a waste heat boiler, mixed with the required amount of air for producing sulfuric acid, and fed to a fabric filter for final cleaning before entering the sulfuric acid unit. The MgO collected in the cyclone and bag filter is recycled to the calciner for layout convenience and to insure calcination of the fines.

A complete 400 tons/day conventional contact sulfuric acid plant is provided for production of 98% acid utilizing the dry inlet gas cleanup system in the calcination area. The sulfuric acid is stored in tanks with an overall storage capacity equivalent to 30 days' production. Tail gas from the acid plant is recycled to the SO_2 scrubbers.

The total land requirement for the base case process for new coal-fired units is approximately 7.8 acres excluding the land requirement for disposing of fly ash. The flow diagram, material balance, control diagram, plot plan, layouts, and elevations are shown in figures 11-19 for the base case, followed by the area-by-area process equipment descriptions.

Magnesium Oxide and Coke Receiving and Storage

This area includes facilities for receiving, by truck or rail, and storing magnesium oxide and coke. The following are provided:

1. One pneumatic MgO unloading - conveying system equipped with a 150-hp blower and a 2-hp rotary lock.
2. One 7,630-ft^3 covered-top MgO storage silo with a 9-ft conical bottom.
3. One 94-ft^3 coke receiving hopper with vibrator and a 12-ft-long x 10-ft-wide x 8-ft-deep unloading pit.
4. One 25-hp Z-type coke conveyor-elevator with a capacity of 15 tons/hr.
5. One 4,130-ft^3 covered-top coke storage silo with a 7.5-ft conical bottom.
6. One 5-gpm, 0.25-hp sump pump.

Feed Preparation

This area includes equipment for producing a slurry of MgO for recycle to the scrubbing area. The following are supplied:

1. One 2-hp recycle MgO weigh feeder equipped with a 1-hp vibrating hopper.
2. One 2-hp makeup MgO weigh feeder equipped with a 1-hp vibrating hopper.
3. One 5-hp Z-type carbon steel conveyor-elevator with a capacity of 8.5 tons/hr.
4. One 105,700-gal, open-top, rubber-lined carbon steel MgO slurrying tank equipped with a 20-hp rubber-coated agitator.
5. Two 263-gpm, 15-hp rubber-lined slurry recycle pumps (1 operating and 1 spare).

Particulate Scrubbers and Inlet Ducts

The particulate scrubbing area for new coal-fired power units includes costs for the following flue gas distribution and particulate scrubbing facilities:

1. Four flue gas ducts between the air heater discharge duct outside the powerhouse and the inlet flue gas plenum.
2. One inlet flue gas plenum interconnecting each of the four flue gas ducts.
3. Four flue gas ducts between the inlet plenum and the particulate scrubber, including one damper per duct.
4. Four 28-ft-diameter x 48.5-ft-high rubber-lined venturi scrubbers equipped with variable throats and stainless steel chevron vane entrainment separators.
5. Four epoxy-lined flue gas ducts between the particulate scrubber outlet and the SO_2 scrubber inlet (one-half of cost is included in this area; the other half is included in the SO_2 scrubbing area).
6. Twenty soot blowers (5 per scrubber).
7. Two 880-gpm, 50-hp vertical, multistage turbine makeup water pumps (1 operating and 1 spare).
8. Four 40,600-gal, rubber-lined carbon steel surge tanks with 20-hp rubber-coated agitators.
9. Six 4,740-gpm, 300-hp rubber-lined centrifugal recirculation pumps (4 operating and 2 spares).
10. Six 113-gpm, 7.5-hp rubber-lined centrifugal slurry disposal pumps (4 operating and 2 spares).
11. Allocation for facilities for neutralizing SO_2 absorbed in the particulate scrubber.

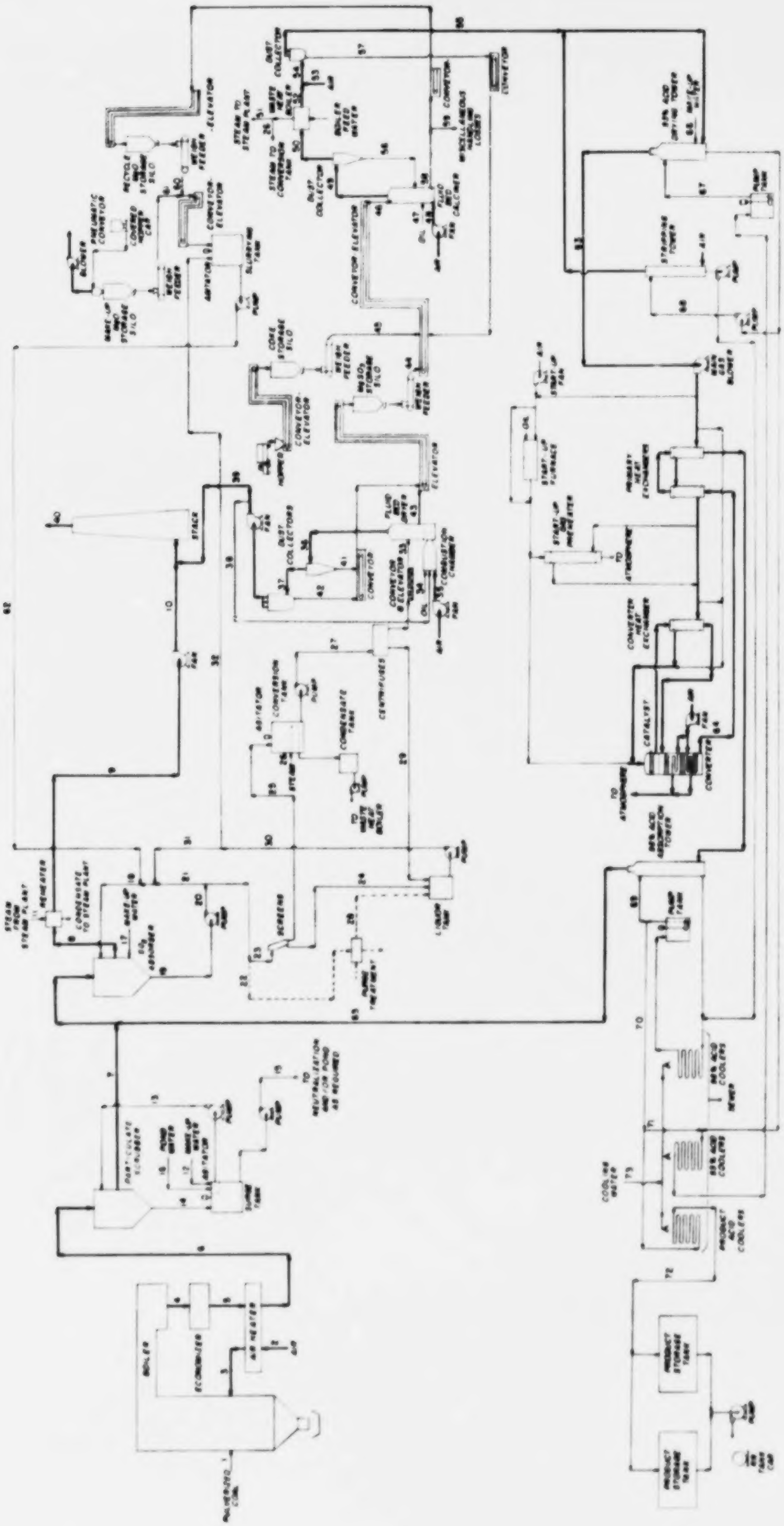

BOILER
ECONOMIZER
AIR HEATER
PARTICULATE SCRUBBER
SO2 ABSORBER
STACK
CENTRIFUGES
CONVERTER
PRODUCT STORAGE TANK

Figure 11. Magnesia slurry - regeneration process. Flow diagram—base case.

STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO PARTICULATE SCRUBBER	GAS TO SO_2 ABSORBER	GAS TO REHEATER	GAS TO FAN	GAS TO STACK	STEAM TO GAS REHEATER	MAKE-UP WATER TO PART SCRBR	RECYCLE SLURRY TO PART SCRBR	PART SCRBR SLURRY TO SURGE TANK	PARTICULATE SLURRY PRODUCT	RECYCLE POND WATER	MAKE-UP WATER TO SO_2 ABSORBER	RECYCLE SLURRY TO SO_2 ABSORBER	SO_2 ABSORBER SLURRY TO PUMP	RECYCLE AND PRODUCT SLURRY
RATE, LBS/HR	375M	4,518M	4,075M	4,404M	4,404M	1,212M	1,267M	1,289M	1,289M	1,289M	15.7M	55M	2,441M	2,394M	56M	47.6M	7,032	3,444M	3,456M	3,456M
SCFM		984M	888M	945M	943M	260M	280M	286M	286M	286M										
GPM												110	4,740	4,649	103	95.1	14.1	6,320	6,341	6,341
PARTICULATES, LBS/HR				33.7M	33.7M	8,439	42.9	56.8	56.8	56.8										
TEMPERATURE, °F		110	555	890	705	310	127	127	160	174	470			127					127	
SPECIFIC GRAVITY													1.03		1.09					1.09
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %													5		15					10
pH														3						8

STREAM NO	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
DESCRIPTION	RECYCLE SLURRY	SLURRY TO PURGE TREATMENT	SLURRY TO SCREEN	UNDERFLOW TO LIQUOR TANK	OVERFLOW TO CONVERSION TANK	STEAM TO CONVERSION TANK	SLURRY TO CENTRIFUGE	TREATED LIQUOR TO LIQUOR TANK	LIQUOR TO LIQUOR TANK	LIQUOR TO RECYCLE	RECYCLE LIQUOR	LIQUOR TO SLURRYING TANK	FEED TO DRYER	OIL TO COMBUSTION CHAMBER	AIR TO COMBUSTION CHAMBER	DRYER GAS TO CYCLONE	DRYER GAS TO BAG COLLECTOR	RECYCLE GAS TO COMBUSTION CHAMBER	DRYER GAS TO STACK	COMBINED GASES TO ATMOSPHERE
RATE, LBS/HR	3,184M	DEPENDS UPON	277M	221M	51M	12.8M	102M	SEE STREAM	68.6M	1,021M	223M	129M	66.4M	2,943	60.5M	136M	136M	45.8M	90.1M	5,246M
SCFM		MAGNESIA AND						22 NOTE							13.2M	35M	35M	11.8M	23.2M	1,187M
GPM	5,842	MAKE-UP	499	421	81.5		170		130	1,944	425	246								
PARTICULATES, LBS/HR		WATER														5,960	894	1.4	2.8	230
TEMPERATURE, °F		IMPURITIES				368	180									400				175
SPECIFIC GRAVITY		FLY ASH		1.05	1.25		1.20		1.06	1.05										
VISCOSITY, CPS		ENTRAINMENT																		
UNDISSOLVED SOLIDS, %		ETC		5.1	40		31		4.8	5.3										
pH																				

STREAM NO	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
DESCRIPTION	CYCLONE DUST TO CONVEYOR	BAG COLLECTOR DUST TO CONVEYOR	DRYER PRODUCT TO CONVEYOR	FEEDER DISCHARGE TO CONVEYOR	CONE TO CONVEYOR	FEED TO CALCINER	OIL TO CALCINER	AIR TO CALCINER	CALCINER GAS TO CYCLONE	CALCINER GAS TO WASTE HEAT BOILER	STEAM TO STEAM PLANT	CALCINER GAS TO QUENCH AIR	QUENCH AIR TO CALCINER GAS	COMBINED GASES TO BAG COLLECTOR	COMBINED GASES TO H_2SO_4 UNIT	CYCLONE DUST TO CALCINER	BAG COLLECTOR DUST TO CONVEYOR	CALCINER PRODUCT TO CONVEYOR	MISC HANDLING LOSSES	RECYCLE MgO TO CONVEYOR
RATE, LBS/HR	5,066	899	33.4M	39.4M	218	39.9M	3,220	46.3M	71.6M	71.6M	3,230	71.6M	62.6M	134M	134M	1,683	294	16.9M	240	16.6M
SCFM								10.1M	13.1M	13.1M		13.1M	13.8M	26.9M	26.9M					
GPM																				
PARTICULATES, LBS/HR									1,980	297		297		297	3					
TEMPERATURE, °F			400						1,600		366	697		400				225		
SPECIFIC GRAVITY																				
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %																				
pH																				

STREAM NO	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
DESCRIPTION	MAKE-UP MgO TO CONVEYOR	MgO SLURRY TO SO_2 ABSORBER	DRYING TOWER OUTLET GAS	CONVERTER OUTLET GAS	ABSORPTION TOWER OUTLET GAS	MAKE-UP WATER TO DRYING TOWER	RECYCLE ACID TO DRYING TOWER	RECYCLE ACID TO STRIPPING TOWER	RECYCLE ACID TO ABSORPTION TOWER	RECYCLE ACID TO COOLERS	RECYCLE ACID TO 93% ACID COOLERS	PRODUCT ACID TO STORAGE	COOLING WATER TO ACID COOLERS							
RATE, LBS/HR	300	36.5M	129M	129M	103M	1,145	1,005M	129M	993M	195M	123M	32.2M	2,370M							
SCFM			25.1M	24.1M	22M															
GPM		65.7				2.29	1,110	148	1,110	173	137	33.4	4,736							
PARTICULATES, LBS/HR												3								
TEMPERATURE, °F			100	840	160		100	163	160			100								
SPECIFIC GRAVITY		1.11					1.81	1.77	1.79			1.82								
VISCOSITY, CPS																				
UNDISSOLVED SOLID, %		15																		
pH																				

NOTES
1. CALCULATIONS BASED ON:
  a. 105% STOICHIOMETRIC MAGNESIA
  b. 3.5% SULFUR IN COAL (DRY BASIS)
  c. 12% ASH COAL (AS FIRED BASIS)
  d. 92% OF SULFUR IN COAL EVOLVES AS SO_2
  e. 75% OF ASH IN COAL EVOLVES AS FLY ASH
  f. 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
  g. 90% SO_2 REMOVAL
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS 6-21, 23-25, 31 & 62 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 27 & 29 ARE ONE OF TWO SIMILAR STREAMS

SYMBOL IN TABLE
M --- THOUSAND

Figure 12. Magnesia slurry - regeneration process. Material balance—base case.

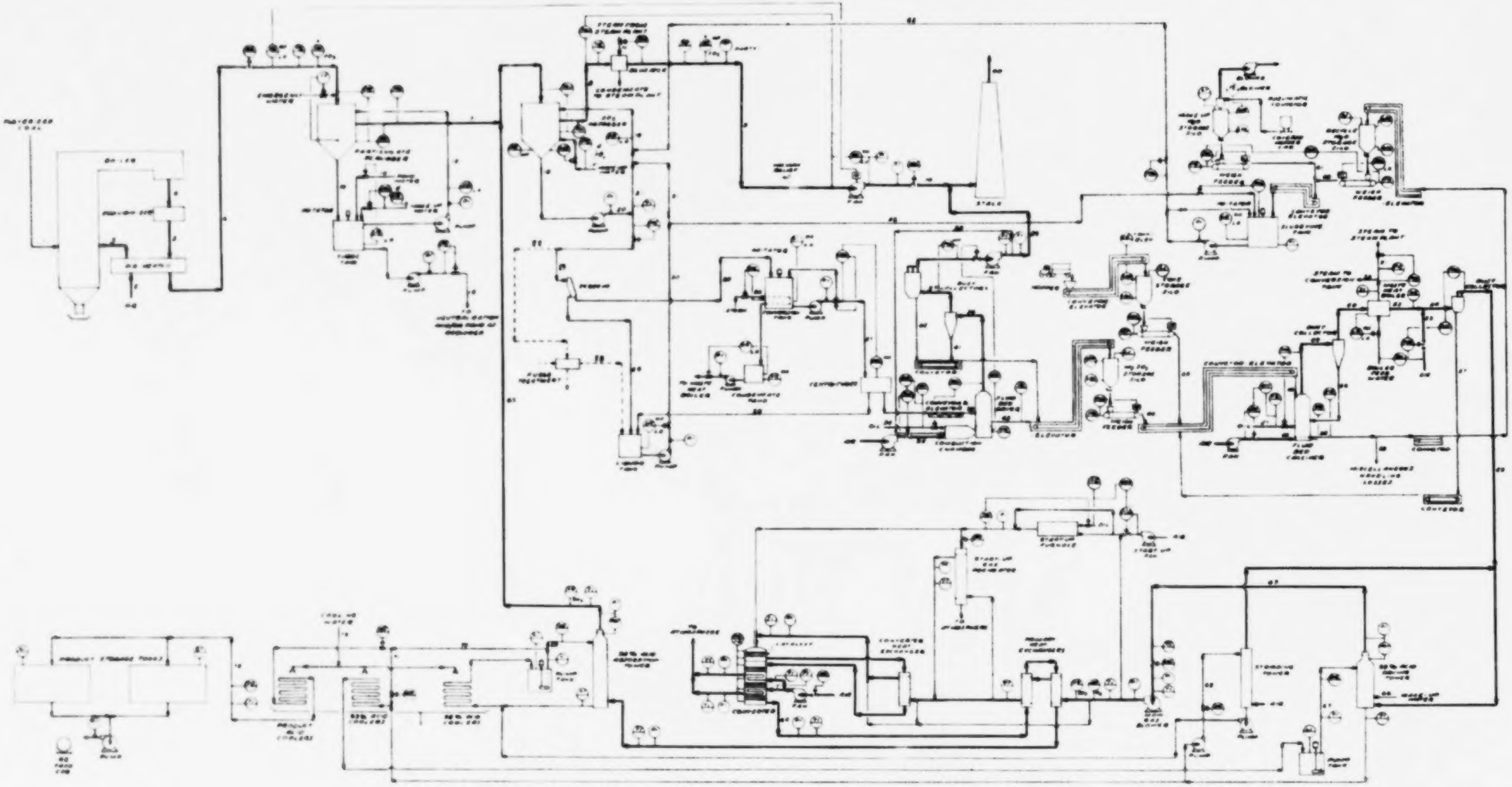
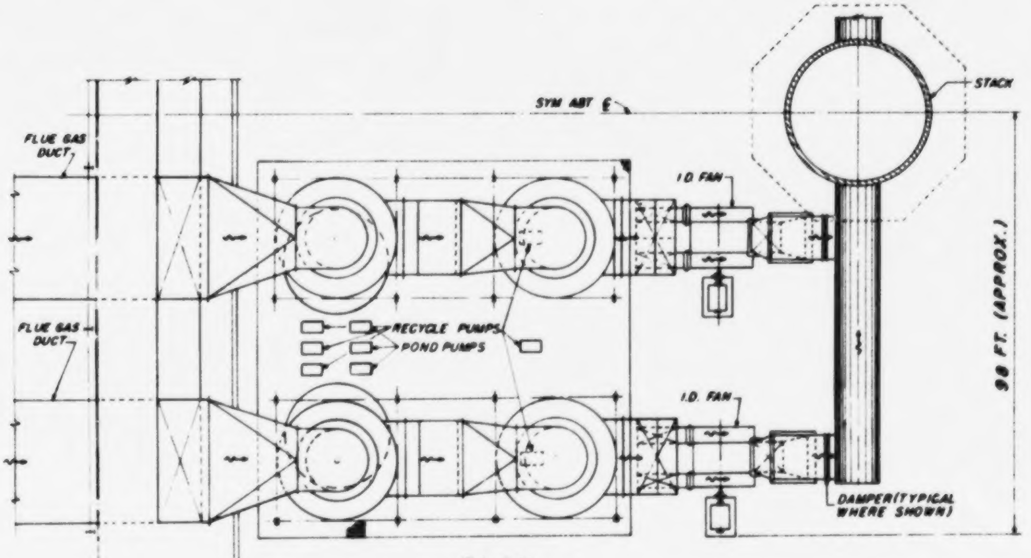


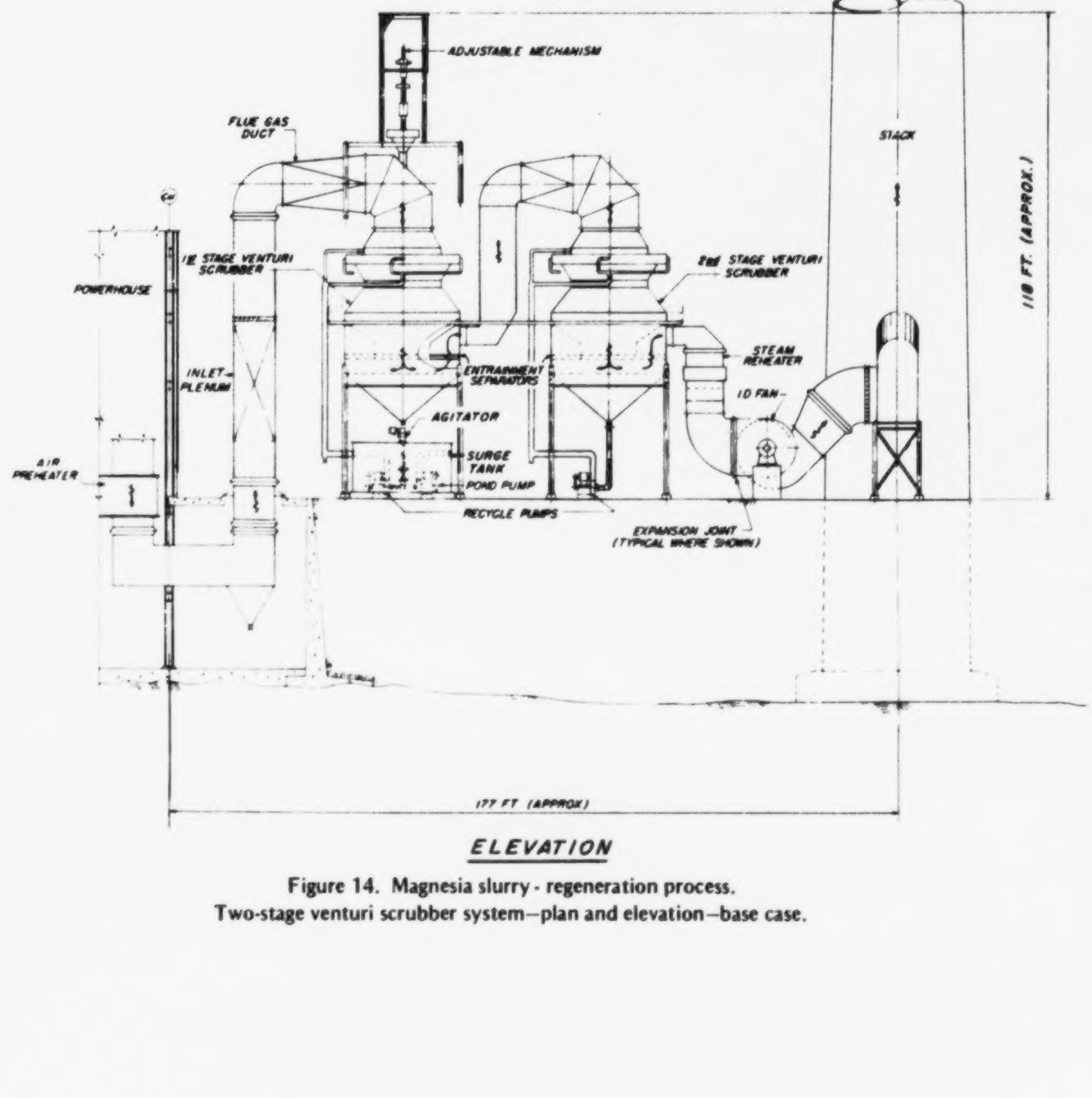
Figure 13. Magnesia slurry - regeneration process. Control diagram--base case.

NOTES:

- a STANDARD ISA IDENTIFICATION LETTERS USED ON INSTRUMENTATION
- b SOOT BLOWER CONTROLS NOT SHOWN
- c ONE ANALYZER WITH 4 ALTERNATE FEEDS
- d ONE INTEGRATOR FOR 8 FLOWS
- e BASIC INSTRUMENTATION SHOWN FOR SULFURIC ACID SYSTEM


FLUE GAS DUCT
SYM ABT ℄
STACK
I.D. FAN
FLUE GAS DUCT
RECYCLE PUMPS
POND PUMPS
I.D. FAN
98 FT. (APPROX.)
DAMPER (TYPICAL WHERE SHOWN)

PLAN


ADJUSTABLE MECHANISM
FLUE GAS DUCT
STACK
118 FT. (APPROX.)
℄
POWERHOUSE
1st STAGE VENTURI SCRUBBER
2nd STAGE VENTURI SCRUBBER
INLET PLENUM
ENTRAINMENT SEPARATORS
STEAM REHEATER
I.D. FAN
AGITATOR
SURGE TANK
POND PUMP
AIR PREHEATER
RECYCLE PUMPS
EXPANSION JOINT (TYPICAL WHERE SHOWN)
177 FT (APPROX)

ELEVATION

Figure 14. Magnesia slurry - regeneration process.
Two-stage venturi scrubber system—plan and elevation—base case.

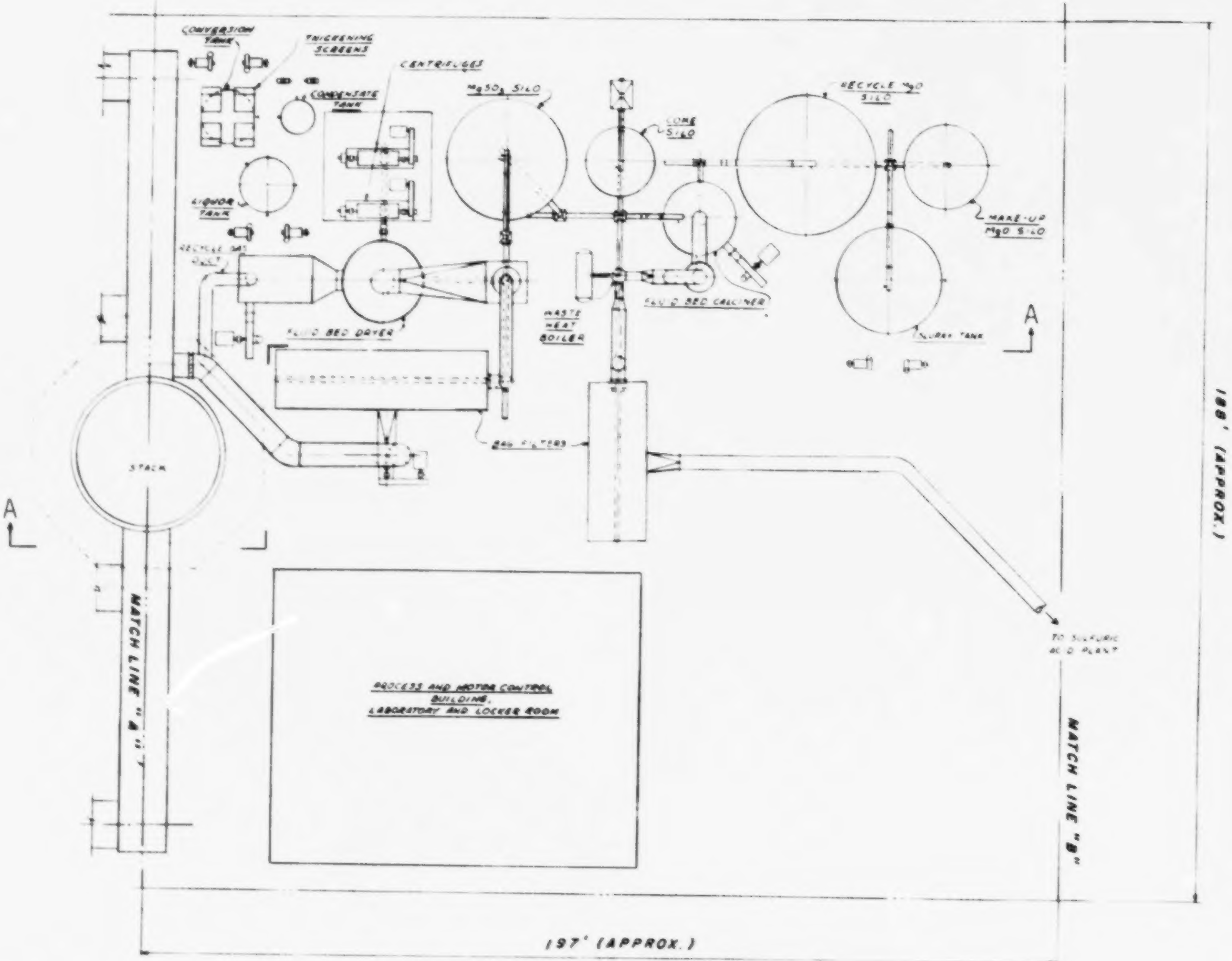

CONVERSION TANK
THICKENING SCREENS
CENTRIFUGES
CONDENSATE TANK
$MgSO_3$ SILO
COKE SILO
RECYCLE MgO SILO
MAKE-UP MgO SILO
SLURRY TANK
LIQUOR TANK
RECYCLE GAS DUCT
FLUID BED DRYER
WASTE HEAT BOILER
FLUID BED CALCINER
BAG FILTERS
STACK
TO SULFURIC ACID PLANT
PROCESS AND MOTOR CONTROL BUILDING, LABORATORY AND LOCKER ROOM
MATCH LINE "A"
MATCH LINE "B"
A
A
188' (APPROX.)
197' (APPROX.)

Figure 15. Magnesia slurry - regeneration process.
Fluid bed dryer–calciner layout–plan–base case.

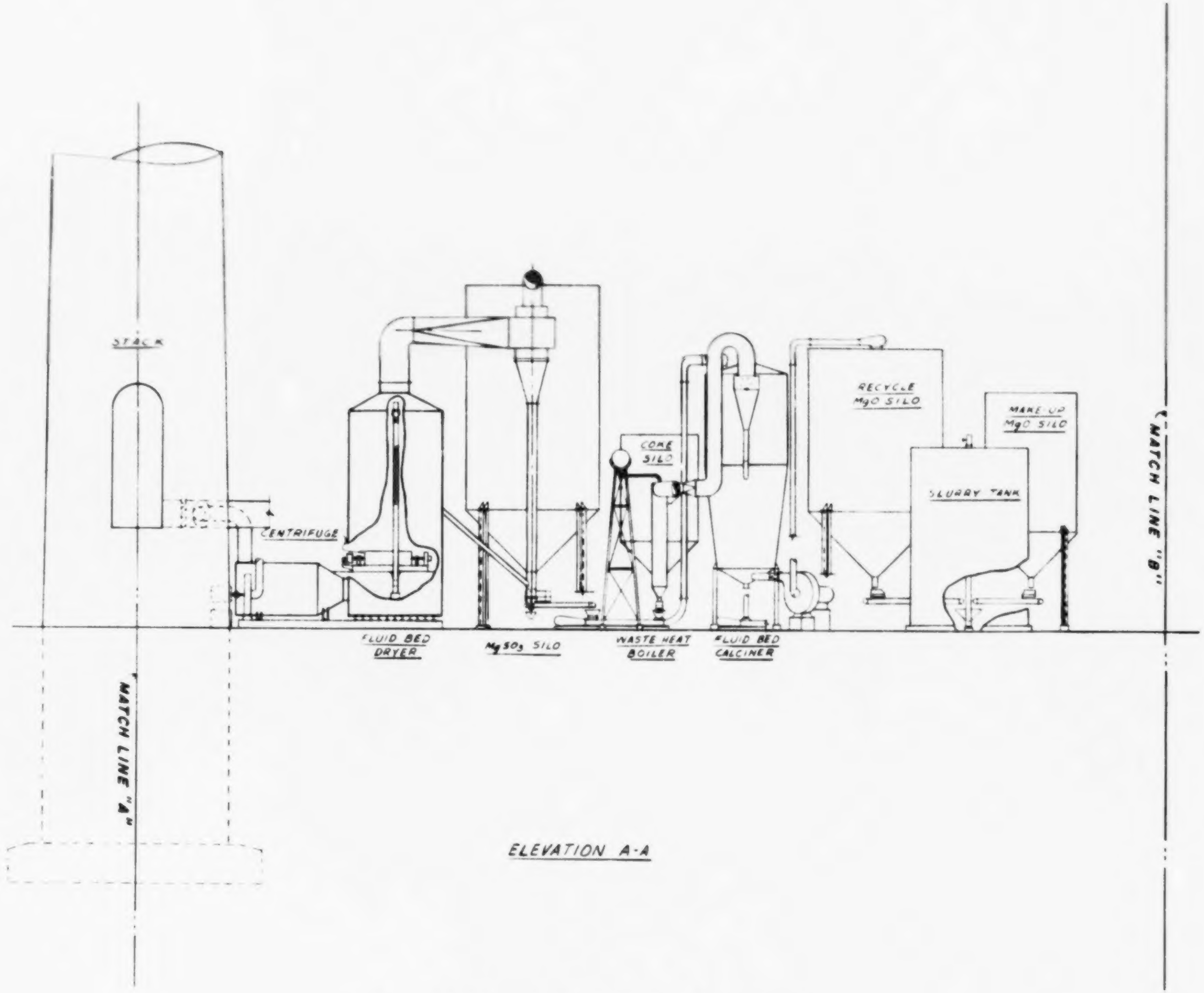

STACK
CENTRIFUGE
FLUID BED DRYER
MgSO3 SILO
COKE SILO
WASTE HEAT BOILER
FLUID BED CALCINER
RECYCLE MgO SILO
SLURRY TANK
MAKE-UP MgO SILO
MATCH LINE "A"
MATCH LINE "B"
ELEVATION A-A

Figure 16. Magnesia slurry - regeneration process.
Fluid bed dryer—calciner layout—elevation—base case.

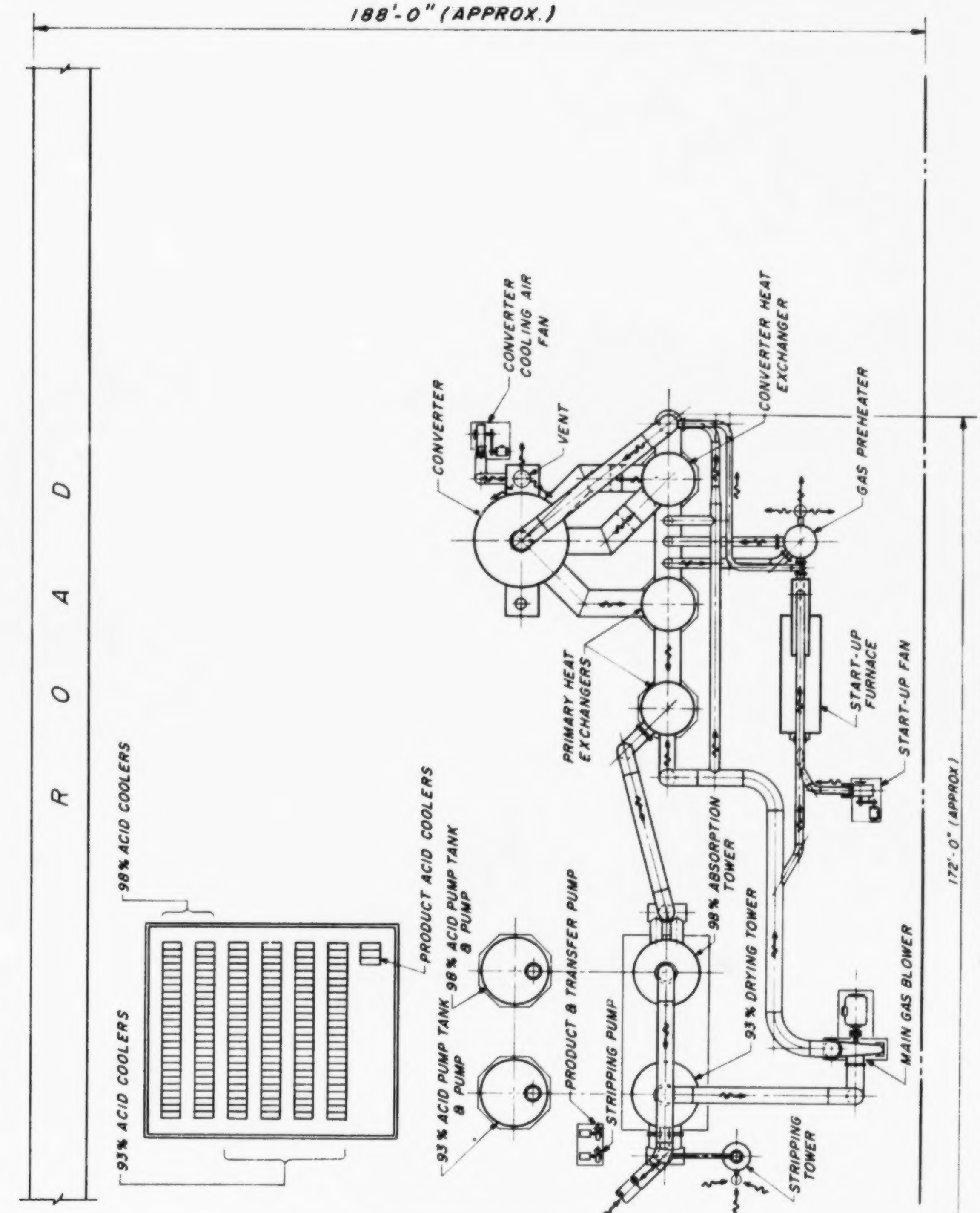

188'-0" (APPROX.)
R O A D
98% ACID COOLERS
93% ACID COOLERS
PRODUCT ACID COOLERS
98% ACID PUMP TANK & PUMP
93% ACID PUMP TANK & PUMP
PRODUCT & TRANSFER PUMP
STRIPPING PUMP
STRIPPING TOWER
93% DRYING TOWER
98% ABSORPTION TOWER
MAIN GAS BLOWER
START-UP FAN
START-UP FURNACE
PRIMARY HEAT EXCHANGERS
GAS PREHEATER
CONVERTER HEAT EXCHANGER
CONVERTER
VENT
CONVERTER COOLING AIR FAN
172'-0" (APPROX)
℄ MATCH LINE "B"

Figure 17. Magnesia slurry - regeneration process. Sulfuric acid unit layout–plan.

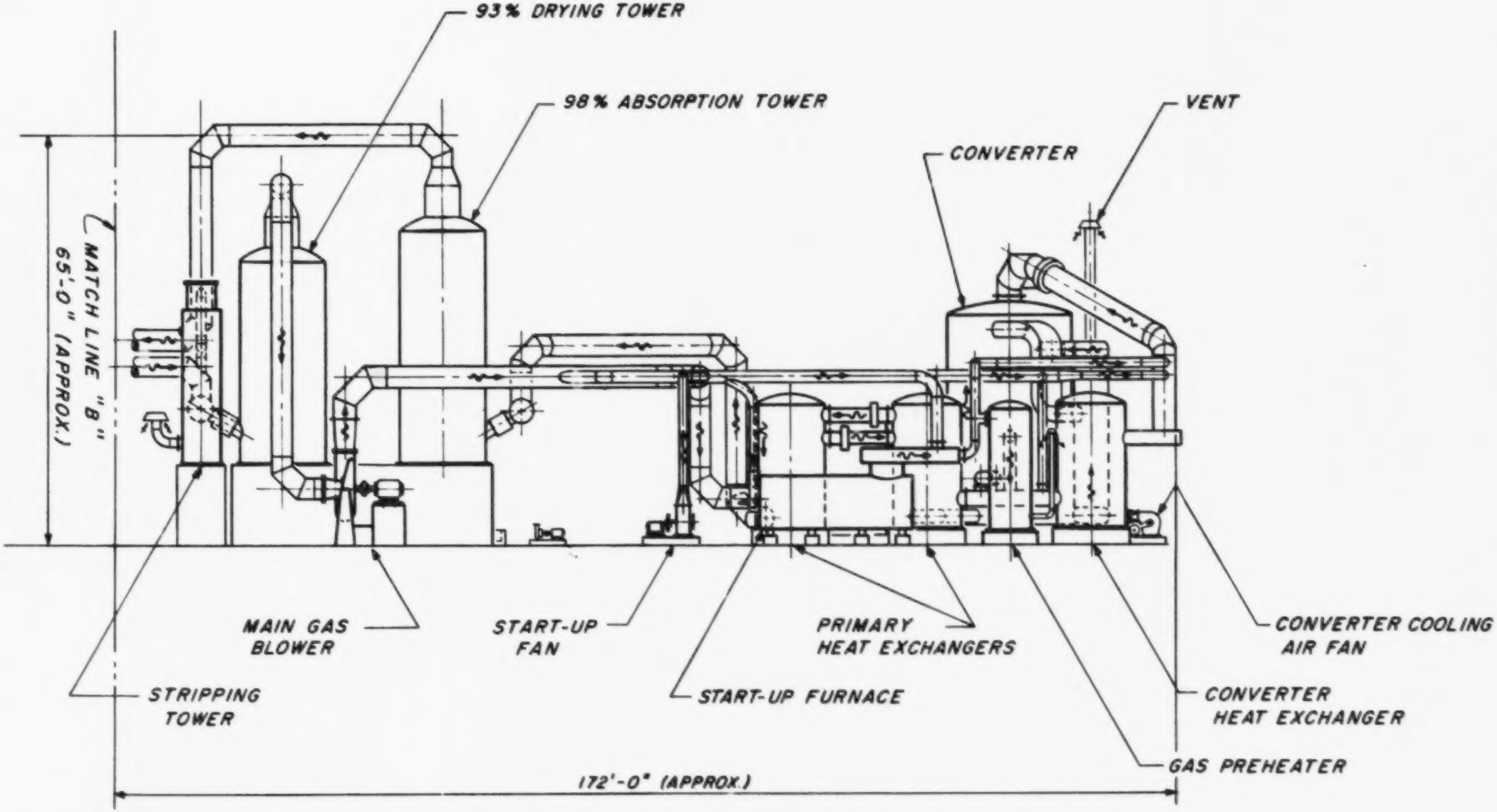

93% DRYING TOWER
98% ABSORPTION TOWER
VENT
CONVERTER
MATCH LINE "B"
65'-0" (APPROX.)
MAIN GAS BLOWER
START-UP FAN
PRIMARY HEAT EXCHANGERS
CONVERTER COOLING AIR FAN
STRIPPING TOWER
START-UP FURNACE
CONVERTER HEAT EXCHANGER
GAS PREHEATER
172'-0" (APPROX.)

Figure 18. Magnesia slurry - regeneration process. Sulfuric acid unit layout—elevation.

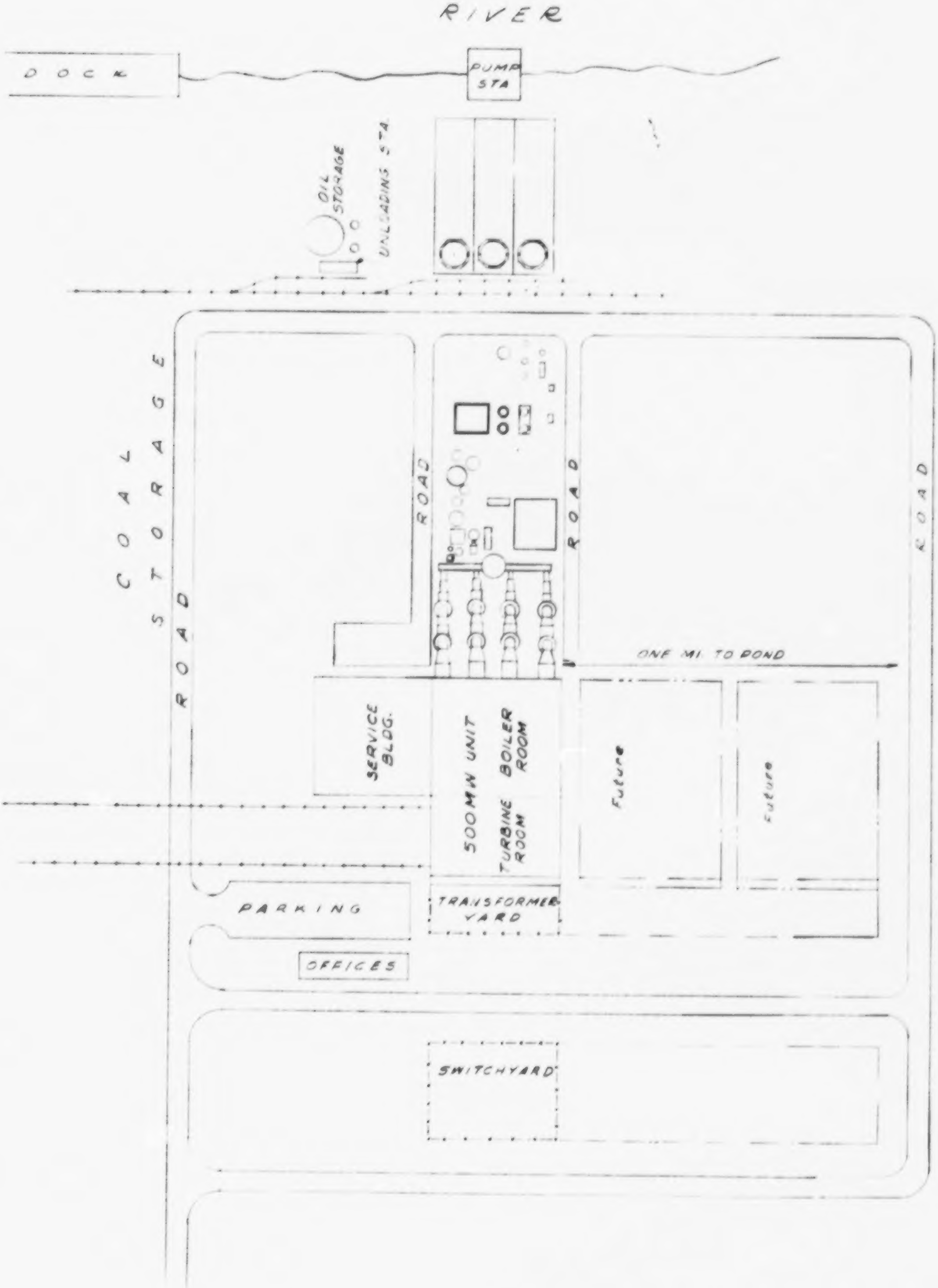

RIVER
DOCK
PUMP STA
OIL STORAGE
UNLOADING STA.
COAL STORAGE
ROAD
ROAD
ROAD
ROAD
ONE MI. TO POND
SERVICE BLDG.
500MW UNIT
BOILER ROOM
TURBINE ROOM
Future
Future
TRANSFORMER YARD
PARKING
OFFICES
SWITCHYARD

Figure 19. Magnesia slurry - regeneration process. Overall plot plan–base case.

Existing coal-fired power units which are already designed to meet particulate emission regulations, and both new and existing oil-fired power units do not require the particulate scrubbing facilities described above.

SO_2 Scrubbers and Ducts

The following equipment is provided:

1. Four flue gas ducts between the particulate scrubber outlet and the SO_2 scrubber inlet (one-half of cost is included in this area; the other half is included in the particulate scrubbing area).
2. Four 28-ft-diameter x 48.5-ft-high rubber-lined venturi scrubbers with stainless steel chevron vane entrainment separators.
3. Twenty soot blowers (5 per scrubber).
4. Four exit flue gas ducts between the SO_2 scrubber outlet and I.D. fan inlet. For existing units, flue gas ducts between the outlet of the supplemental F.D. fan and the inlet to the stack gas plenum are included.
5. Six 6,320-gpm, 300-hp rubber-lined centrifugal recirculation pumps (4 operating and 2 spares).

Stack Gas Reheat

This area includes facilities for reheating the gas to obtain an outlet stack gas temperature of 175°F. The reheat method utilized in the magnesia slurry - regeneration process is similar to the method utilized in the limestone slurry process with one exception. A small portion of reheat for the magnesia slurry - regeneration process (about 5°F) is obtained by mixing filtered dryer off-gas (temperature approximately 400°F) with the scrubbed flue gas in the stack gas plenum. Table 19 shows the temperature increase in degrees Fahrenheit required to obtain an exit temperature of 175°F at the stack outlet.

A new 500-MW coal-fired power unit is designed with four 1,658-ft^2 indirect steam (500-psig) tube-type heat exchangers (one per duct) constructed within the exit flue gas ducts upstream of the fan. One-half of the tubes (scrubber side) are Inconel 625 and the other half (fan side) are Cor-Ten. Twenty soot blowers are provided (5 per reheater) for periodic cleaning of the tubes.

Existing coal-fired units and new and existing oil-fired units are designed with four direct oil-fired reheaters which discharge hot combustion gases into each duct.

Fans

Fan location, method of costing, and duct configuration for the magnesia slurry - regeneration process are similar to that described for the limestone slurry process with the exception of pressure drop. Table 20 identifies the pressure drop distribution provided for each of the various system designs.

The following are included in the base case investment and operating cost estimates:

1. Incremental costs for four 3,000-hp (38 in. △P) induced draft fans. Prorated for 23 inches of pressure drop attributed to particulate and SO_2 removal.
2. Four exit flue gas ducts between I.D. fans and stack gas plenum.

Slurry Processing

The liquor containing absorbed SO_2 is pumped from the absorbers to the slurry processing area for thickening, thermal conversion of $MgSO_3 \cdot 6H_2O$ to $MgSO_3 \cdot 3H_2O$ and separation of solids prior to drying. This is achieved with the following equipment:

1. Four 316 stainless steel wet screens mounted in 4-ft-long x 5-ft-wide x 8-ft-high vertical housings.
2. One 5,000-gal, rubber-lined liquor tank, 9-ft-diameter x 10-1/2-ft-high.
3. Two 1,440-gpm, 50-hp rubber-lined liquor pumps (1 operating and 1 spare).
4. One 6,300-gal, 12-ft-diameter x 7-1/2-ft-high, stainless steel, field fabricated conversion tank with a 20-hp stainless steel agitator.

Table 19. Flue Gas Reheat Requirements–Magnesia Slurry - Regeneration Process

Power unit		Required temperature increase, °F
Type	Status	
Coal fired	New	33
Coal fired	Existing	47
Oil fired	New	31
Oil fired	Existing	40

Table 20. Assumed Pressure Drop Distribution for Specifications of Fans–Magnesia Slurry - Regeneration Process

Power unit			Pressure drop distribution, inches H_2O attributed to		
Fuel	Status	SO_2 removal efficiency, %	Power production	SO_2 removal	Total
Coal	New	90	15.0	23.0[b]	38.0
Coal	Existing	90	–[a]	12.5	12.5
Oil	New	90	15.0	10.5	25.5
Oil	Existing	90	–[a]	12.5	12.5
Coal	New	80	15.0	21.5[b]	36.5
Coal	Existing (requiring particulate scrubber)	90	–[a]	23.0[b]	23.0

[a] Existing power units already have fans which overcome the pressure drop attributed to power production.

[b] Includes pressure drop attributed to both particulate and SO_2 removal.

5. One 1,200-ft^2 stainless steel steam coil.
6. Two 340-gpm, 10-hp, rubber-lined conversion tank pumps (1 operating and 1 spare).
7. Two parallel, 36-in.-diameter, x 72-in.-long, stainless steel solid bowl centrifuges equipped with two 200-hp motors.
8. One 100-gal condensate tank.
9. One 25-gpm, 5-hp condensate pump.
10. One 20-ft-long x 16-in.-diameter horizontal stainless steel screw conveyor equipped with a 5-hp motor.
11. One 40-ft-long x 16-in.-diameter vertical stainless steel screw conveyor equipped with a 5-hp motor.

Drying

Costs for the following magnesium sulfite drying equipment and the dryer exhaust gas distribution and cleaning system are included in this area:

1. One 18-ft-diameter x 40-ft-high single-stage, refractory-lined, carbon steel, fluid bed dryer equipped with a 10-ft-diameter x 16-ft-long oil-fired combustion chamber, a 250-hp fluidizing-combustion air blower and a refractory-lined cyclone to partially clean the dryer off-gas.
2. One 46-ft-long x 12.5-ft-wide x 21-ft-high fabric dust collector designed to filter 57,900 acfm of gas at 400°F.
3. One 250-hp I.D. exhaust gas fan.
4. One 25-hp, Z-type conveyor-elevator for transporting the dust collector, cyclone, and dryer solids to the $MgSO_3$ storage silo.
5. One 25,500-ft^3 $MgSO_3$ storage silo equipped with a vibrating hopper.

Calcining

This area includes facilities for calcining $MgSO_3$ to regenerate MgO and produce SO_2 for sulfuric acid production. The following equipment is provided:

1. One 2-hp $MgSO_3$ vibratory feeder.
2. One 2-hp $MgSO_3$ weigh feeder.
3. One 1-hp coke vibratory feeder.
4. One 2-hp coke weigh feeder.
5. One 25-hp Z-type conveyor-elevator for transporting $MgSO_3$ from the storage silo to the fluid bed calciner.
6. One 16-ft-diameter x 38-ft-high refractory-lined, carbon steel, fluid bed calciner equipped with 1 calcining bed and 2 air preheat - MgO cooling beds. Fuel oil is atomized directly into the calcining bed. Combustion air is supplied by a 400-hp blower. A refractory-lined cyclone is provided to partially clean the calciner off-gas.
7. One waste heat boiler system with a 22-in.-diameter x 20-ft-long boiler and a 30-in.-diameter x 20-ft-long feed water tank.
8. One 34-ft-long x 12.5-ft-wide x 21-ft-high fabric dust collector designed to filter 40,000 acfm of gas at 400°F.
9. One 15-hp, Z-type conveyor-elevator for transporting MgO from the calciner to the recycle MgO silo.
10. One 18,950-ft^3 recycle MgO storage silo equipped with a vibrating hopper.
11. One 2.5-hp Z-type conveyor-elevator for recycling fines from the bag filter to the fluid bed calciner feed conveyor-elevator.

Sulfuric Acid Plant

This area provides costs for 1 complete 400 tons/day conventional contact sulfuric acid plant, utilizing the dry inlet gas cleanup system provided in the calcination area. The sulfuric acid unit tail gas is fed to the SO_2 absorber to eliminate SO_x emission resulting from the production of acid.

Sulfuric Acid Storage and Shipping

The following sulfuric acid storage and loading facilities are included in the base case investment estimate:

1. Three 500,000-gal carbon steel storage tanks.
2. Two 400-gpm, 40-hp sulfuric acid loading pumps (1 operating and 1 spare).
3. One railroad car loading dock.
4. One dike constructed around the sulfuric acid storage tanks.

Utilities

Facilities for the generation and distribution of utilities for the magnesia slurry - regeneration process are similar to the limestone slurry process facilities except for the quantities involved and the requirement of fuel oil distribution and storage facilities for both new and existing units. All units utilize fuel oil for drying and calcining. A 660,000-gallon storage tank and two 24,000-gallon hold tanks are provided for the base case installation. Existing coal-fired and both new and existing oil-fired units provide for additional fuel oil storage for stack gas reheat similar to the reheat method for the limestone slurry process.

Service Facilities

The following items are included in the estimate for each of the various system designs:

1. Vehicles—allocation to power unit for use of plant vehicles.

2. **Buildings and equipment**—one 5,800-ft² maintenance and instrument shop; one 5,000-ft² building including process and motor control facilities, laboratory, lockers, offices, and restrooms; allocation to power unit for one 2,300-ft² stores area.
3. Railroads—costs for 3,600-ft of track, 5 switches, and 2 car pullers.
4. Parking lot, walkways, and approximately 1 mile of paved roads.
5. Landscaping, fencing, and security.

Construction Facilities

Construction facilities are projected as 5% of the subtotal area investments similar to the method used for the limestone slurry process.

SODIUM SOLUTION - SO_2 REDUCTION PROCESS

In the sodium solution - SO_2 reduction process, fly ash is removed by wet scrubbing flue gas in a venturi by contact with a slurry of fly ash in water; SO_2 is absorbed from the gas by an aqueous sodium sulfite scrubbing solution in a separate scrubber. For this regeneration process, makeup soda ash is added to replace the sodium value lost in handling and as byproduct sodium sulfate formed in the scrubber and removed as purge. The makeup soda ash is pneumatically conveyed from hopper cars or trucks to a storage bin and fed to a tank where it is slurried in water along with antioxidant. The antioxidant is added to minimize the oxidation of sulfites to sulfates in the absorber. The soda ash and antioxidant slurry is pumped to a Na_2SO_3 dissolving tank for generation of the scrubber solution. Recycle pond water and makeup humidification water are fed to the venturi particulate scrubbers for removal of fly ash from the gas as in the magnesia process. The fly ash slurry is neutralized with slaked lime as required and pumped to the power plant ash disposal pond.

Separate scrubbing loops are provided for each of the three trays in the valve-tray SO_2 absorber. The absorbers are equipped with fleximesh mist eliminators. A purge stream consisting of approximately 58% of the absorber effluent is routed to a purge treatment area where it is cooled for crystallization and subsequent removal of sodium sulfate from the liquor. After purge, the liquor is recombined with the remaining absorber effluent. The sodium sulfate is dried in a rotary dryer and conveyed to a product storage bin. Steam is used in new coal-fired units to provide heat for the dryer; whereas, existing coal and both new and existing oil-fired units utilize fuel oil as a heat source. The dryer off-gas is cleaned with a cyclone and fabric filter and routed to the scrubbing system.

The combined absorber effluent and purge stream, after removal of the sodium sulfate, is pumped to a single-effect evaporator-crystallizer in the regeneration area to crystallize Na_2SO_3 and regenerate SO_2 for the reduction area. The off-gas containing regenerated SO_2 from the evaporator-crystallizers is cooled to condense some of the water vapor. Most of the remaining moisture is removed as the SO_2 gas is compressed. The condensate is used to solubilize the Na_2SO_3 for return to the SO_2 absorber.

The compressed SO_2 gas is fed to the Allied Chemical reduction unit where it is mixed with natural gas and indirectly preheated by the cooling of reduced gas. The combined gases flow into a reduction reactor system where these are reduced to S, H_2S, CO_2, and H_2O. The reduced gas mixture is cooled in a hot water/gas heat exchanger before entering a condenser-converter-condenser system where most of the H_2S and SO_2 are converted to S. The S formed during the reaction is condensed. A coalescer is used to remove the small drops of sulfur prior to treatment of the tail gas. The molten sulfur is collected in a sulfur receiving pit and stored in steam-heated tanks for shipment. The tail gas from the reduction unit is incinerated with natural gas and air to oxidize any H_2S formed during the reduction process to SO_2 and is returned to the scrubbing system.

The total land requirement for the base case process for new coal-fired units is approximately 7.7 acres excluding the land requirement for fly ash disposal. The flow diagram, material balance, plot plan, layouts, and elevations for the sodium solution - SO_2 reduction process are shown in figures 20-25 for the base case and an area-by-area description is given.

Soda Ash and Antioxidant
Receiving, Storage, and Preparation

This area includes facilities for receiving, by truck or rail, and storing soda ash, and equipment for producing a mixture of soda ash and antioxidant. The following equipment is provided:

1. One pneumatic soda ash unloading conveying system.
2. One 4,500-ft³ soda ash closed-top storage bin equipped with 2 bin vibrators.
3. One 1-hp vibrating feeder.
4. One 2-hp soda ash weigh feeder equipped with a 1-hp vibrating hopper.
5. One 1-hp antioxidant feeder.
6. One 11,800-gal rubber-lined mixing tank equipped with baffles and a 3-hp rubber-coated agitator.
7. Two 25-gpm, 1-hp, rubber-lined horizontal, centrifugal, mixing tank pumps (1 operating and 1 spare).

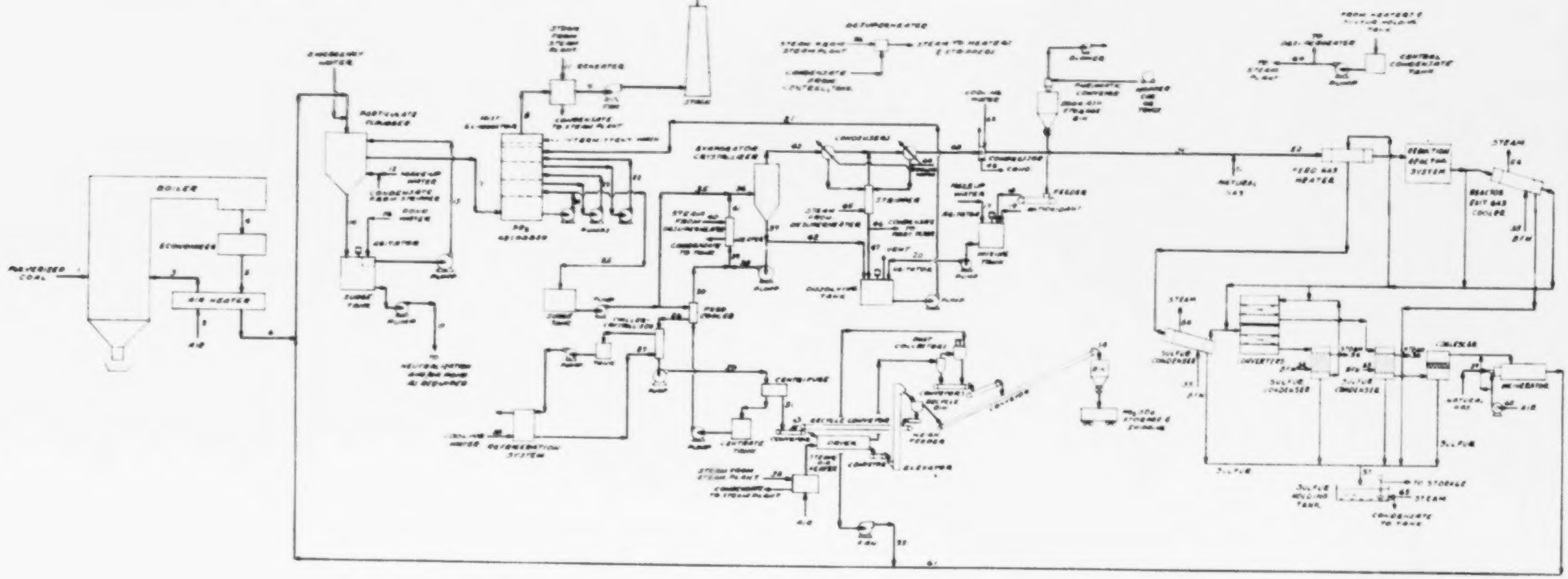

PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
EMERGENCY WATER
PARTICULATE SCRUBBER
MAKE-UP WATER
CONDENSATE FROM STRIPPER
AGITATOR
SURGE TANK
PUMP
MIST ELIMINATORS
SO_2 ABSORBER
PUMPS
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
STACK
DESUPERHEATER
STEAM TO HEATERS & STRIPPERS
EVAPORATOR CRYSTALLIZER
CONDENSERS
STRIPPER
STEAM FROM DESUPERHEATER
VENT
DISSOLVING TANK
MIXING TANK
COOLING WATER
COMPRESSOR
FEEDER
PNEUMATIC CONVEYOR
STORAGE BIN
NATURAL GAS
FEED GAS HEATER
REDUCTION REACTOR SYSTEM
STEAM
REACTOR EXIT GAS COOLER
BFW
TO DEAERATOR
TO STEAM PLANT
CENTRAL CONDENSATE TANK
FEED COOLER
CHILLER-CRYSTALLIZER
TANK
REFRIGERATION SYSTEM
CENTRIFUGE
CENTRATE TANK
RECYCLE CONVEYOR
DRYER
CONVEYOR
ELEVATOR
DUST COLLECTORS
RECYCLE BIN
MIXER FEEDER
BIN
Na_2SO_4 STORAGE & SHIPPING
FAN
SULFUR CONDENSER
CONVERTERS
COALESCER
INCINERATOR
SULFUR
SULFUR HOLDING TANK
TO STORAGE
CONDENSATE TO TANK

Figure 20. Sodium solution - SO_2 reduction process. Flow diagram—base case.

STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO PARTICULATE SCRUBBER	GAS TO SO2 ABSORBER	GAS TO REHEATER	GAS TO FAN	GAS TO ATMOSPHERE	STEAM TO GAS REHEATER	MAKE UP WATER TO PART SCRBR	RECYCLE SLURRY TO PART SCRBR	PART SCRBR SLURRY TO SURGE TANK	PARTICULATE SLURRY PRODUCT	RECYCLE POND WATER	MAKE UP WATER TO MIXING TANK	SODA ASH TO MIXING TANK	ANTIOXIDANT TO MIXING TANK	MAKE UP TO DISSOLVING TANK
RATE LBS/HR	375M	4,518M	4,075M	4,404M	4,404M	1,212M	1,317M	1,312M	1,312M	5,248M	15M	50.4M	2,441M	2,449M	55.9M	476M	10.6M	2,890	45.3	13.3M
SCFM		984M	881M	943M	945M	280M	292M	290M	290M	1,180M										
GPM												101	4,740	4,798	103	95.1	21.2			22.2
PARTICULATES LBS/HR				33.7M	33.7M	6,435	42.9	55.8	55.8	225										
TEMPERATURE °F		110	535	890	700	310	127	127	163	175	470			127						100
SPECIFIC GRAVITY													1.03		1.09					1.20
VISCOSITY CPS																				
UNDISSOLVED SOLIDS %													5		15					
pH														3						

STREAM NO	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
DESCRIPTION	FEED SOLUTION TO SO2 ABSORBER	RECYCLE TO THIRD STAGE	RECYCLE TO SECOND STAGE	RECYCLE TO FIRST STAGE AND PRODUCT	LIQUOR TO SURGE TANK	LIQUOR TO CHILLER CRYSTALLIZER	E.G. SOLUTION TO CHILLER CRYSTALLIZER	COOLING WATER TO REFRIG SYSTEM	SLURRY TO CENTRIFUGE	CENTRATE TO HEATER	CAKE TO CONVEYOR	STEAM TO STEAM/AIR HEATER	GAS FROM DRYER	PURGE TO BIN	LIQUOR TO EVAP CRYSTR	FEED TO EVAP CRYSTR	SLURRY FROM EVAP CRYSTR	SLURRY TO HEATER	FEED TO HEATER	STEAM TO HEATER
RATE LBS/HR	872M	5.5M	608M	705M	92.6M	214M	1,395M	389M	214M	205M	9,380	20.4M	188M	5,712	78.1M	60.1MM	60MM	59.9MM	60MM	115M
SCFM													407M							
GPM	141	65	657	1,102	145	334	2,807	777	334	320					122	68.7M	68.6M	68.5M	68.6M	
PARTICULATES LBS/HR																				
TEMPERATURE °F						68	25		30	98		470	230							220
SPECIFIC GRAVITY							1.07													
VISCOSITY CPS																				
UNDISSOLVED SOLIDS %																				
pH																				

STREAM NO	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
DESCRIPTION	SLURRY TO EVAP CRYSTR	SLURRY TO DISSOLVING TANK	VAPOR TO PRIMARY CONDENSER	WATER TO CONDENSERS	STEAM TO STRIPPER	CONDENSATE TO PART SCRBR	CONDENSATE TO DISSOLVING TANK	GAS TO COMPRESSOR	CONDENSATE	GAS TO SO2 REDUCTION	NATURAL GAS TO SO2 REDUCTION	MIXED GASES TO FEED GAS HEATER	RECYCLE PURGE TO DRYER	STEAM TO STEAM PLANT	BFW TO CONDENSERS & GAS COOLER	STEAM TO DESUPER-HEATER	SULFUR TO STORAGE & SHIPPING		NATURAL GAS TO INCINERATOR	AIR TO INCINERATOR
RATE LBS/HR	60MM	72.7M	10.7M	5,568M	3,668	5,163	95.6M	10.7M	369	20.6M	3,306	23.9M	55.5M	9.5M	13.7M	225M	9,342		243	8,813
SCFM			35.4M					1,208		2,280	1,150	5,410							83	1,830
GPM	68.6M	65		11.1M		10.3	191								11.9		10.4			
PARTICULATES LBS/HR																				
TEMPERATURE °F					220					250	200		220	250	230	470				70
SPECIFIC GRAVITY																				
VISCOSITY CPS																				
UNDISSOLVED SOLIDS %																				
pH																				

STREAM NO	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
DESCRIPTION	GAS FROM INCINERATOR	COOLING WATER TO GAS COMPRESSOR	STEAM TO SULFUR STORAGE	CONDENSATE TO STEAM PLANT																
RATE LBS/HR	23.6M	74M	3000	228M																
SCFM	5,450																			
GPM		148		450																
PARTICULATES LBS/HR																				
TEMPERATURE °F	1,250		298																	
SPECIFIC GRAVITY																				
VISCOSITY CPS																				
UNDISSOLVED SOLIDS %																				
pH																				

NOTES

CALCULATIONS BASED ON
- a 105% STOICHIOMETRIC SODIUM
- b 3.5% SULFUR IN COAL (DRY)
- c 12% ASH COAL (AS FIRED)
- d 92% OF SULFUR IN COAL EVOLVES AS SO_2
- e 75% OF ASH IN COAL EVOLVES AS FLY ASH
- f 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
- g 90% SO_2 REMOVAL

2 PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE

3 STREAM NUMBERS 6, 9, 11-16 & 21-25 ARE ONE OF FOUR SIMILAR STREAMS

4 STREAM NUMBERS 35-49 & 62 ARE ONE OF TWO SIMILAR STREAMS

SYMBOLS IN TABLE

M ---- THOUSAND

MM ---- MILLION

Figure 21. Sodium solution - SO_2 reduction process. Material balance–base case.

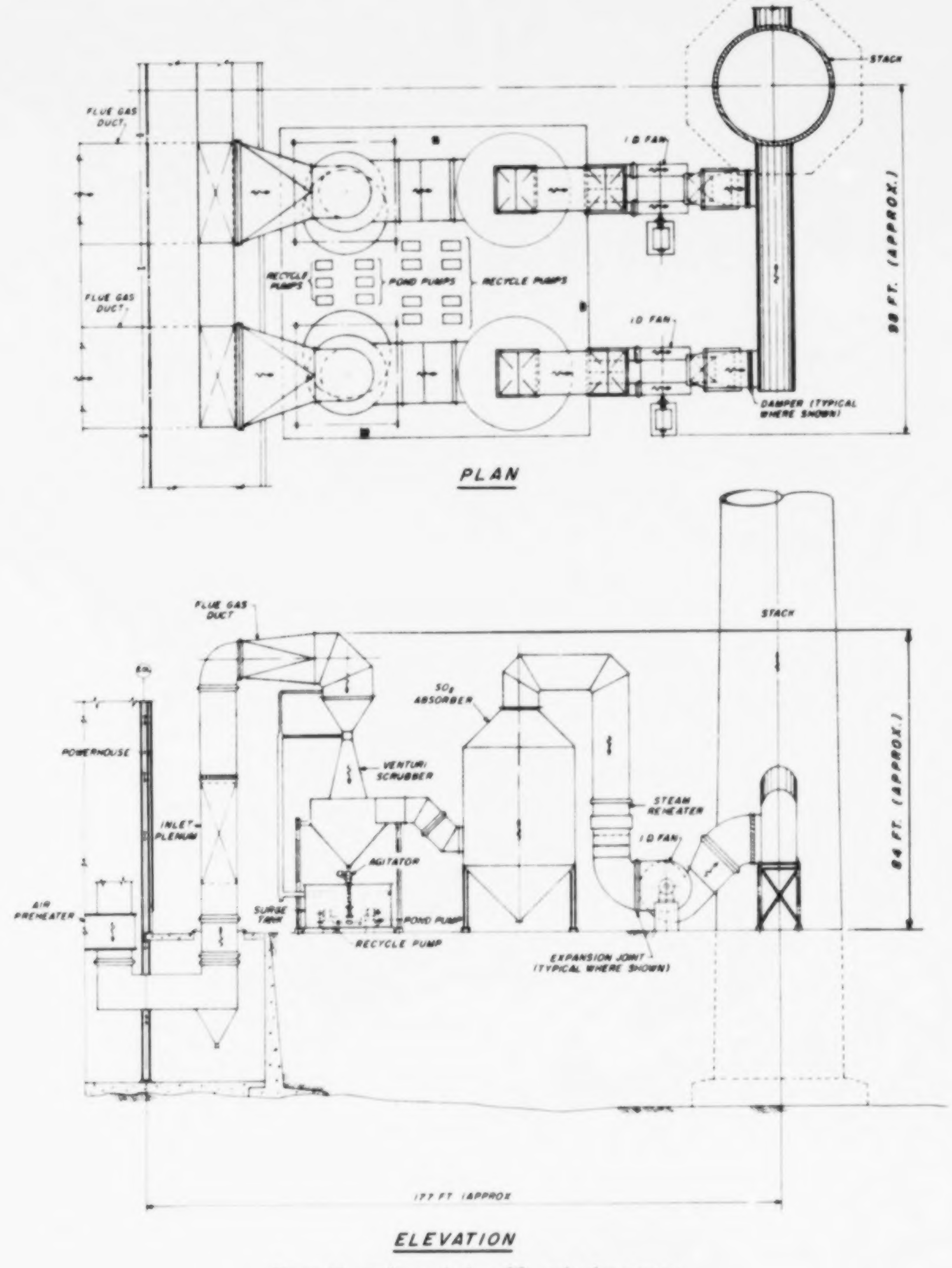

FLUE GAS DUCT
FLUE GAS DUCT
RECYCLE PUMPS
POND PUMPS
RECYCLE PUMPS
I D FAN
I D FAN
STACK
DAMPER (TYPICAL WHERE SHOWN)
98 FT. (APPROX.)
PLAN
FLUE GAS DUCT
STACK
SO2 ABSORBER
VENTURI SCRUBBER
POWERHOUSE
INLET PLENUM
STEAM REHEATER
I D FAN
AGITATOR
AIR PREHEATER
SURGE TANK
POND PUMP
RECYCLE PUMP
EXPANSION JOINT (TYPICAL WHERE SHOWN)
84 FT. (APPROX.)
177 FT (APPROX
ELEVATION

Figure 22. Sodium solution - SO_2 reduction process.
Venturi and valve-tray scrubber system—plan and elevation—base case.

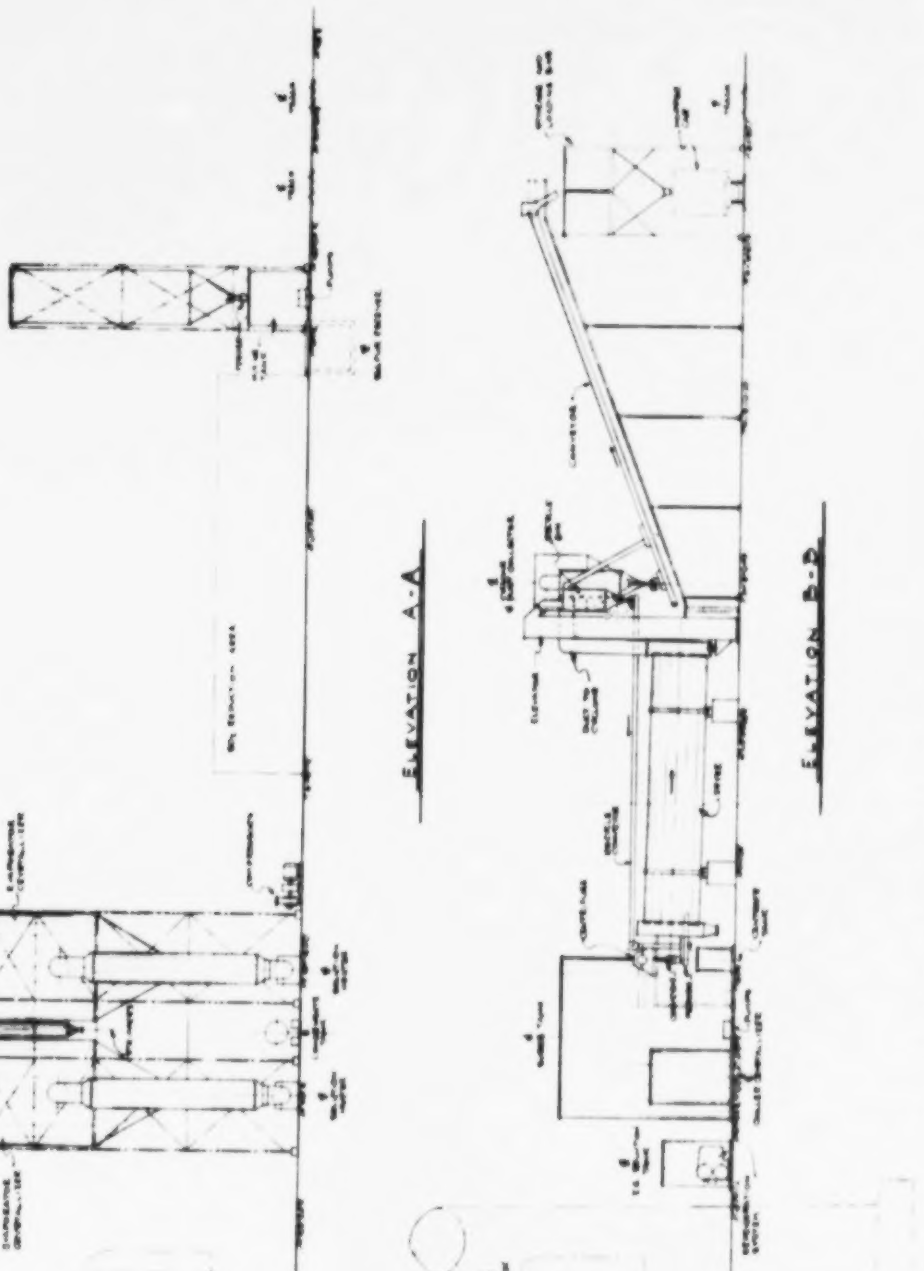

ELEVATION A-A
ELEVATION B-B

Figure 23. Sodium solution - SO_2 reduction process. SO_2 regeneration–reduction and purge treatment system layout–elevation–base case.

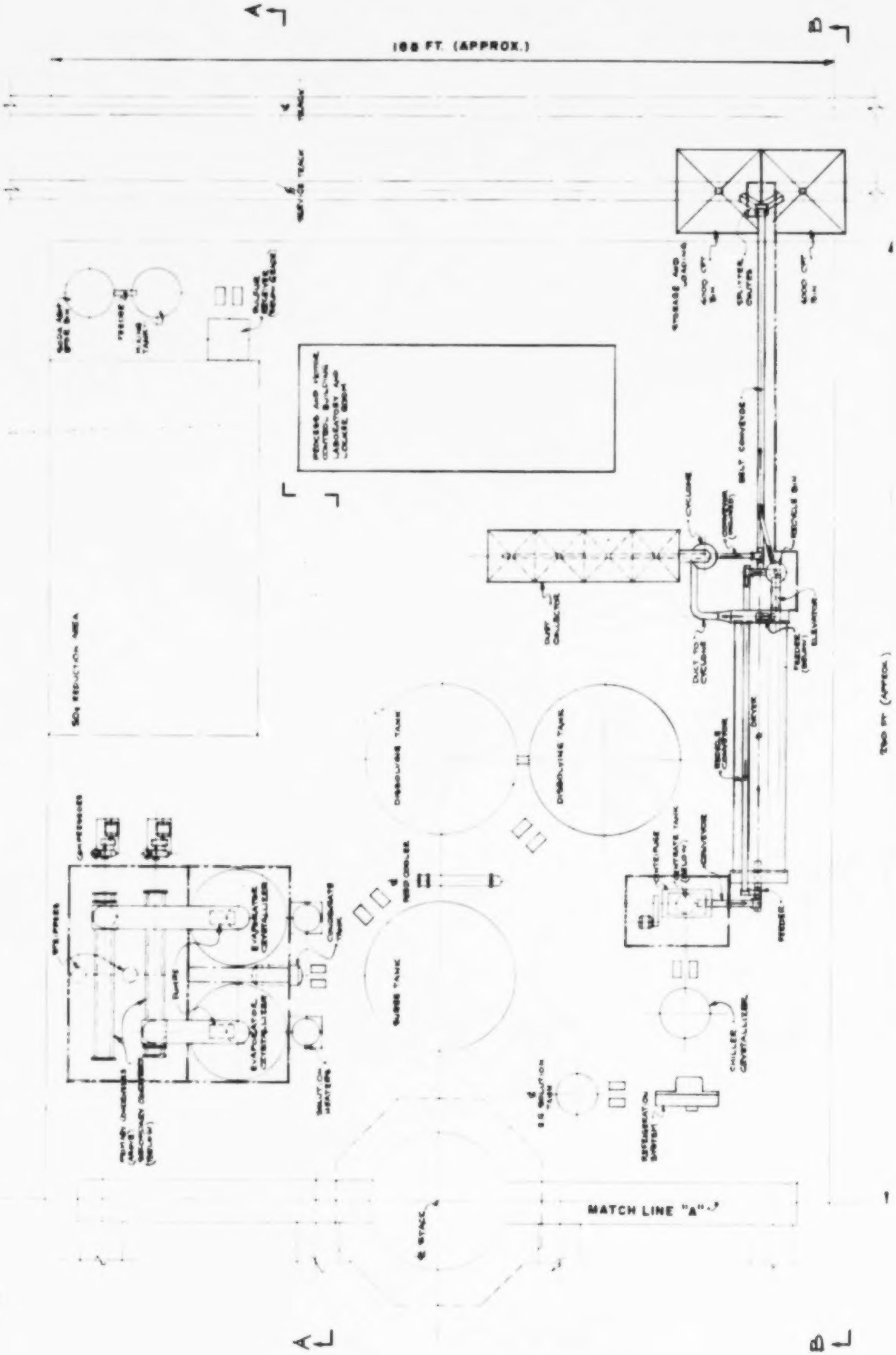

A
B
188 FT. (APPROX.)
MATCH LINE "A"
SURGE TANK
DISSOLVING TANK
DISSOLVING TANK
SO2 REDUCTION AREA
DUST COLLECTOR
CYCLONE
BELT CONVEYOR
STORAGE AND LOADING
EVAPORATOR CRYSTALLIZER
EVAPORATOR CRYSTALLIZER
CHILLER CRYSTALLIZER
CENTRIFUGE
DRYER
FEEDER
ELEVATOR
STACK

Figure 24. Sodium solution - SO_2 reduction process. SO_2 regeneration–reduction and purge treatment layout–plan–base case.

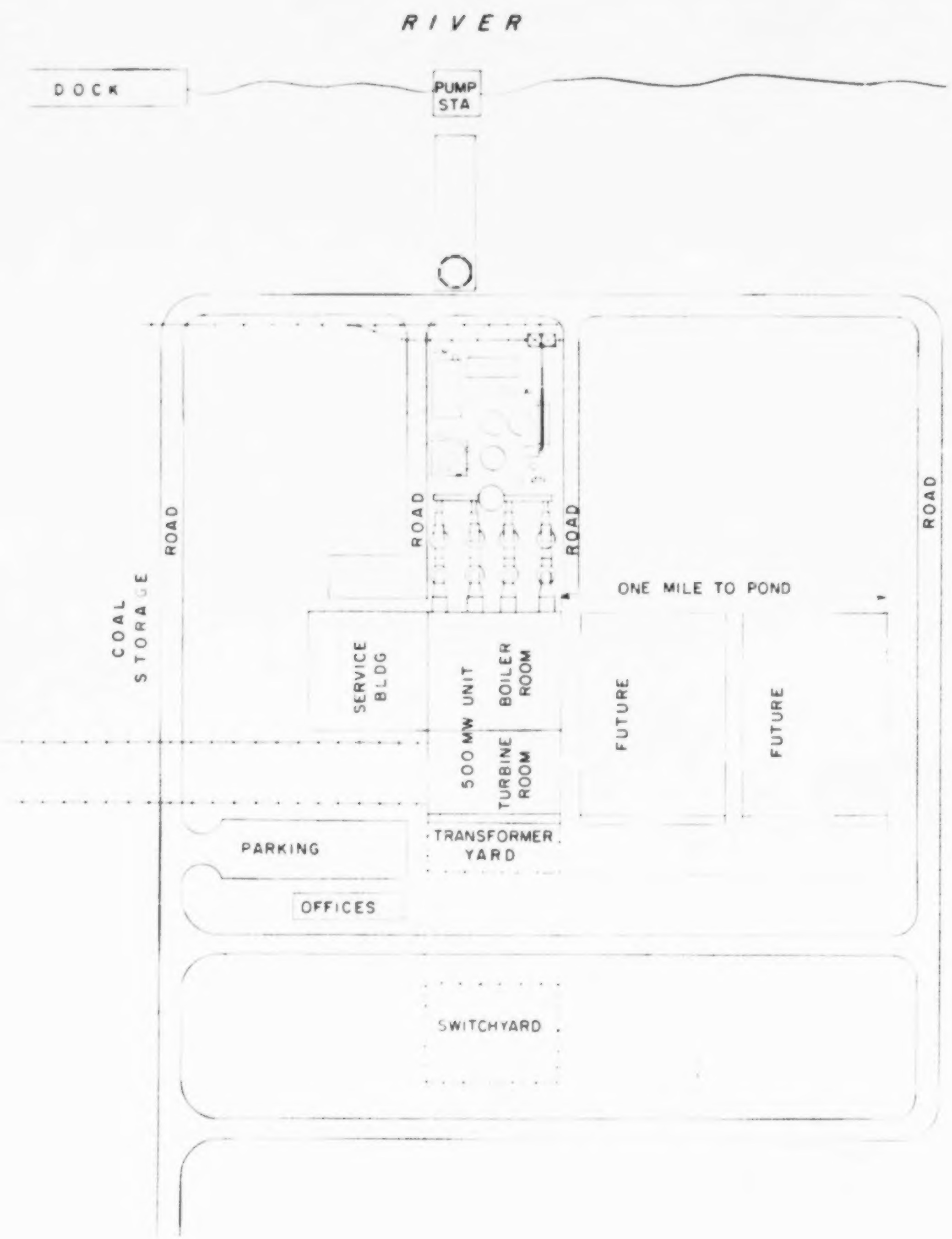

RIVER
DOCK
PUMP STA
ROAD
ROAD
ROAD
ROAD
COAL STORAGE
SERVICE BLDG
500 MW UNIT
BOILER ROOM
TURBINE ROOM
ONE MILE TO POND
FUTURE
FUTURE
TRANSFORMER YARD
PARKING
OFFICES
SWITCHYARD

Figure 25. Sodium solution - SO_2 reduction process. Overall plot plan–base case.

Particulate Scrubbers and Inlet Ducts

The particulate scrubbing areas for the magnesia slurry - regeneration process and the sodium solution - SO_2 reduction process are similar. A list of the flue gas distribution and particulate scrubbing facilities included in the estimate is given in the description for the magnesia slurry - regeneration process particulate scrubbers and inlet ducts area.

SO_2 Scrubbers and Ducts

The following equipment is provided:

1. Four flue gas ducts between the venturi particulate scrubber outlet and the SO_2 scrubber inlet (one-half of cost is included in this area; the other half is included in the particulate scrubbing area).
2. Four 31-ft-diameter x 60-ft-high carbon steel, fiberglass-lined three-plate valve-tray SO_2 absorbers with stainless steel internals and fleximesh mist eliminators with fiberglass lining.
3. Sixteen 1,000-gpm, 35-hp, rubber-lined, centrifugal solution recycle pumps.
4. Four exit flue gas ducts between the SO_2 scrubber outlet and I.D. fan inlet. For existing units, flue gas ducts and inlet plenum are included between the outlet of the supplemental F.D. fan and the inlet to the stack gas plenum.

Stack Gas Reheat

This reheat system is similar to the reheat system described for the limestone slurry process stack gas reheat area. Table 21 shows the temperature increase in degrees Fahrenheit required to obtain an exit temperature of 175°F at the stack outlet.

Fans

Fan location, method of costing, and duct configuration for the sodium solution - SO_2 reduction process are similar to that described for the limestone slurry process with the exception of pressure drop. Table 22 identifies the pressure drop distribution provided for each of the various system designs.

Purge Treatment

A purge stream of effluent from the SO_2 absorber is routed to the purge treatment area for removal of sodium sulfate from the system. The separation, drying, storage, and shipping of sodium sulfate is achieved with the following equipment:

1. One 500-ton refrigeration system.
2. Two 2,621-gpm, 200-hp, horizontal, centrifugal ethylene glycol pumps (1 operating and 1 spare).
3. One 8,800-gal, 10-ft-diameter x 15-ft-high, insulated, flat-top ethylene glycol tank.
4. One 12-ft-diameter x 18-ft-high, insulated, 304 stainless steel chiller-crystallizer tank with 8,400-ft^2 cooling surface and a 5-hp rubber-coated agitator.
5. Two 350-gpm, 10-hp, horizontal, centrifugal chiller-crystallizer pumps (1 operating and 1 spare).
6. One 1,529-ft^2, shell and tube, 316 stainless steel feed cooler.
7. One 36-in.-diameter x 96-in.-long stainless steel solid bowl centrifuge equipped with a 300-hp motor.
8. One 960-gal, closed-top, 316 stainless steel centrate tank.
9. Two 350-gpm, 15-hp, rubber-lined, horizontal, centrifugal centrate pumps.
10. One 1-hp, enclosed, belt conveyor for transporting sodium sulfate from the centrifuge and recycle conveyor to the dryer.
11. One 12-ft-diameter x 60-ft-long rotary dryer.
12. One 1-hp, enclosed, belt conveyor between the dryer and elevator.
13. One 7.5-hp, bucket elevator for transporting sodium sulfate to the recycle bin.

Table 21. Flue Gas Reheat Requirements–
Sodium Solution - SO_2 Reduction Process

Power unit		Required temperature
Type	Status	increase, °F
Coal fired	New	36
Coal fired	Existing	51
Oil fired	New	34
Oil fired	Existing	44

Table 22. Assumed Pressure Drop Distribution
for Specification of Fans–
Sodium Solution - SO_2 Reduction Process

Power unit			Pressure drop distribution, inches H_2O attributed to		
Fuel	Status	SO_2 removal efficiency, %	Power production	SO_2 removal	Total
Coal	New	90	15.0	26.5[b]	41.5
Coal	Existing	90	[a]	16.0	16.0
Oil	New	90	15.0	14.0	29.0
Oil	Existing	90	[a]	16.0	16.0
Coal	New	80	15.0	24.0[b]	39.0
Coal	Existing (requiring particulate scrubber)	90	[a]	28.5[b]	28.5

[a] Existing power units already have fans which overcome the pressure drop attributed to power production.

[b] Includes pressure drop attributed to both particulate and SO_2 removal.

14. One 1-hp recycle sodium sulfate weigh feeder with a 1-hp vibrating feeder.
15. One 100-ft^3, closed-top, side and bottom feed, recycle bin.
16. One 1-hp, enclosed, sodium sulfate, recycle belt conveyor.
17. One 46-ft-long x 12.5-ft-wide x 21-ft-high, fabric dust collector designed to filter 57,900 acfm of gas.
18. One 250-hp induced draft exhaust gas fan.
19. One finned-tube steam/air heater with 735 ft^2 of air cooler area.
20. Two 1-hp enclosed belt dust conveyors.
21. One 3-hp, enclosed belt conveyor for loading the sodium sulfate storage bin.
22. One 8,000-ft^3, sodium sulfate storage and loading bin with divider and 4 bin vibrators.

Existing coal-fired and both new and existing oil-fired units are equipped with an oil-fired drying system to replace the steam/air heater and dryer provided for new coal-fired units. The following equipment is provided for the oil-fired drying system:

1. One 8-ft-diameter x 60-ft-long rotary dryer.
2. One 7.5-hp primary air fan.
3. One 30-hp secondary air fan.
4. One direct oil-fired heater system.

SO_2 Regeneration

The absorber effluent is pumped to the regeneration area where Na_2SO_3 is crystallized and SO_2 and H_2O are evolved by evaporating the $NaHSO_3$ solution. Most of the H_2O is removed from the single-effect evaporator-crystallizer vapor and is used to solubilize the Na_2SO_3 for return to the SO_2 absorber. The following equipment is provided:

1. One 278,400-gal, rubber-lined, surge tank.
2. Two 600-gpm, 40-hp, rubber-lined, horizontal, centrifugal surge tank pumps (1 operating and 1 spare).
3. Two 19,065-ft^2, shell and tube heaters with carbon steel shell and 304 stainless steel tubes and heads.
4. Two 24-ft-diameter x 26-ft-high, 304 stainless steel, evaporator-crystallizers.
5. Two 70,000-gpm, 800-hp, 304 stainless steel, horizontal, axial flow, evaporator-crystallizer circulation pumps.
6. Two 7,593-ft^2, shell and tube primary condensers with carbon steel shell and 316 stainless steel tubes and heads.
7. Two 2,013-ft^2, shell and tube secondary condensers with carbon steel shell and 316 stainless steel tubes and heads.
8. Two 3-ft-diameter x 16-ft-high, 316 stainless steel strippers.
9. Two 152,300-gal, rubber-lined dissolving tanks equipped with baffles and two 10-hp, rubber-coated agitators.
10. Two 600-gpm, 40-hp, rubber-lined, horizontal, centrifugal, dissolving tank pumps (1 operating and 1 spare).
11. Two 1,268-scfm, 250-hp compressors.
12. One 9,408-gal, insulated, horizontal, central condensate tank.
13. Two 600-gpm, 30-hp, horizontal, centrifugal, condensate pumps (1 operating and 1 spare).
14. One desuperheater with a 500-psig steam throughput capacity of 250,000 lb/hr.

As stated earlier in the premises, existing coal- and oil-fired units are equipped with packaged boiler units to provide steam for the regeneration area heaters and strippers. The desuperheater is not required for the existing units.

SO_2 Reduction

This area includes one complete SO_2 reduction unit with a capacity of 112 short tons sulfur per day. Compressed SO_2 gas is mixed with natural gas and preheated in a gas heat exchanger by cooling reduced gas. A reduction reactor system reduces the gas mixture to S, H_2S, CO_2, and H_2O. Subsequent cooling of the reduced gas occurs in a gas/steam heat exchanger and the preheater discussed above. The cooled reduced gas is passed through a condenser-converter-condenser system where most of the H_2S and SO_2 is converted to S which is condensed. A coalescer is utilized to remove small drops of entrained sulfur from the tail gas before it is incinerated with natural gas and air to convert any sulfur compounds in the offgas to SO_2. The combustion gas is returned to the SO_2 absorber to eliminate SO_x emission resulting from the production of sulfur. This Allied Chemical process is a recent proprietary development and a complete description of the reduction unit is not available.

Sulfur Storage and Shipping

The following facilities are included in the estimate for sulfur storage and loading:

1. One 10-ft-long x 10-ft-wide x 10-ft-high sulfur-receiving pit with insulation and a 304 stainless steel cover.
2. Four 125-gpm, 10-hp, high-temperature, sulfur-loading pumps with steam tracing and insulation (2 operating and 2 spare).
3. One 467,100-gal, closed-top, insulated sulfur storage tank.
4. One railroad car loading dock.
5. One dike constructed around the sulfur storage tank.

Utilities

Facilities for the generation and distribution of utilities for the sodium solution - SO_2 reduction process are similar to those provided for the limestone slurry process, but differ somewhat in quantities. However, new and existing coal- and oil-fired units all require that steam be provided for the SO_2 regeneration and sulfur storage areas. Existing coal-fired units require fuel oil storage and distribution facilities for reheat drying, and producing steam for the SO_2 regeneration and sulfur storage areas. New oil-fired units are equipped with a 500-psig supply system from the power unit for the SO_2 regeneration and sulfur storage areas, and fuel oil storage and distribution facilities for reheating and drying.

Service Facilities

The following items are included in the estimate:

1. Vehicles allocation to power unit for use of plant vehicles.
2. Buildings and equipment one 5,800-ft² maintenance and instrument shop; one 5,000-ft² building including process and motor control facilities, laboratory, lockers, offices, and restrooms; allocation to power unit for one 2,300-ft² stores area.
3. Railroads costs for 1,100 ft of track, 1 switch, and 1 car puller.
4. Parking lot, walkways, and approximately 1 mile of paved roads.
5. Landscaping, fencing, and security.

Units with fuel oil storage and distribution facilities include an additional 800 feet of railroad track and two switches in this area for fuel oil receiving and handling.

Construction Facilities

Construction facilities are projected as 5% of the subtotal area investments similar to the method used for the limestone slurry process.

CATALYTIC OXIDATION PROCESS

The Cat-Ox process utilizes vanadium pentoxide catalyst to convert SO_2 to SO_3 directly in the flue gas followed by the absorption of the SO_3 to produce nominal 80% acid. Efficient conversion of SO_2 to SO_3 requires a gas temperature of approximately 850°-900° F. For new units (integrated process) the facilities are designed for conversion upstream of the economizers and air preheaters to eliminate the necessity of additional heat transfer equipment. For existing units (reheat process) direct oil-fired flue gas reheaters are provided to reheat the gas to the proper temperature prior to conversion and additional heat exchangers are included to recover this heat downstream. Based on the Wood River experience it is recognized that the direct oil-fired reheat system should be designed for external combustion with injection into the ducts, with provisions for bypassing the converters during startup of the reheaters.

Both new and existing units require high efficiency electrostatic precipitators for reducing the particulate loading of the gas to the converters to 0.005 gr/scf or less to minimize fouling of the catalyst. Bypass ducts and dampers around the converters and absorbers prevent contamination of the catalyst and acid during startup. Even with these precautions, there is a gradual buildup of fly ash on the catalyst during operation. Conversion efficiency of the catalyst is not affected by this buildup; however, there is a gradual increase in pressure drop across the converter due to the collection of fly ash. Therefore, equipment is provided to convey, clean, and return the catalyst to the converter system. Approximately 2.5% of the total volume of catalyst must be replaced per cleaning because of catalyst losses resulting from screening and mechanical breakage during the sifting operation. Under normal conditions the catalyst must be cleaned about every 3 months.

Sulfur trioxide and a portion of the water vapor in the flue gas are absorbed in packed towers with a recirculating stream of sulfuric acid from the heat recovery fluid loops. Entrained sulfuric acid and mist particles formed as the gas cools are removed by high efficiency Brink fiber demisters.

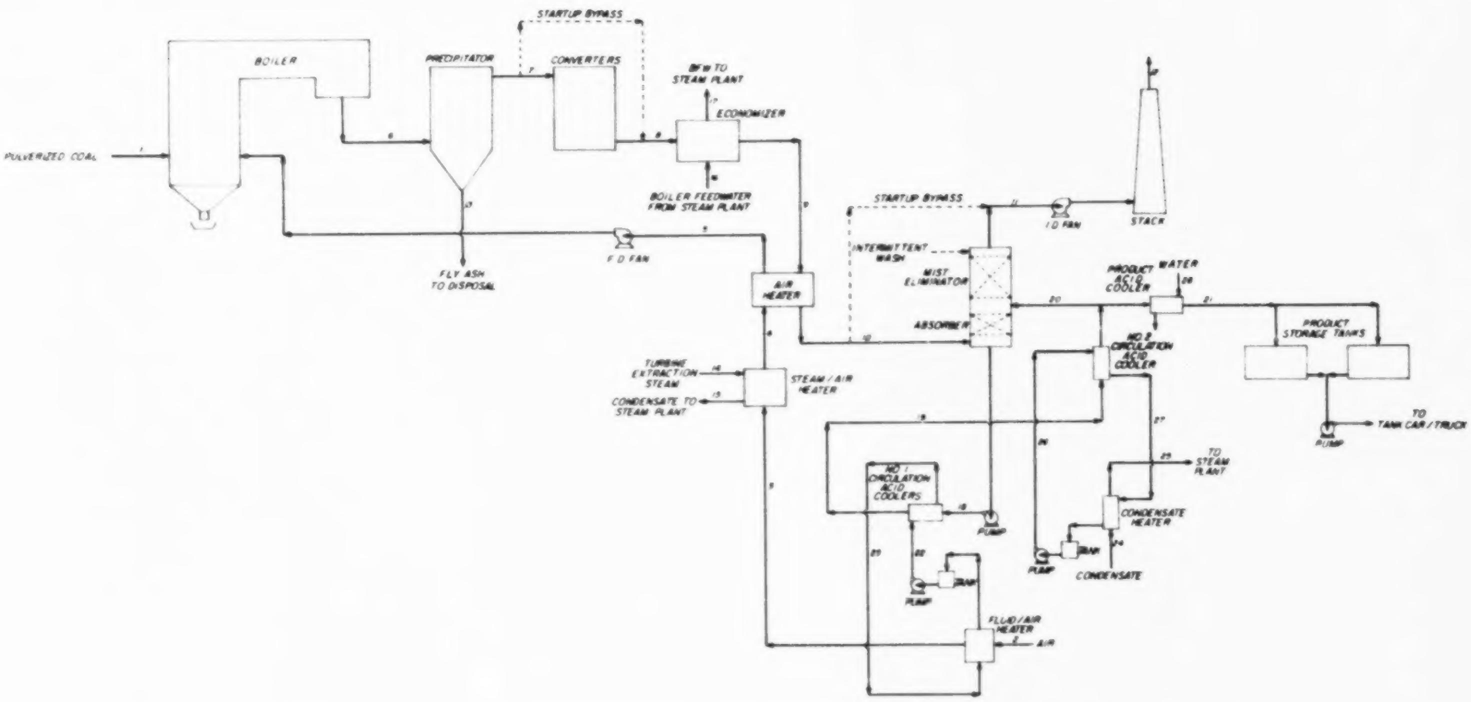
For energy conservation, about half of the heat of absorption of SO_2 from an integrated unit is transferred to the power plant boiler combustion air by means of a fluid loop. Additional heat is transferred to boiler feed water in the same manner. For a reheat unit, cooling water is used to recover the heat of absorption. A steam/air heater for new coal-fired units and a direct oil-fired reheater for oil-fired units are provided to supply supplemental heat to the combustion air.

For each process, the product acid is cooled further and pumped to the product storage tanks for shipment.

Approximately 7.4 acres of land are required for new 500-MW coal-fired units utilizing the Cat-Ox process excluding the land requirement for fly ash disposal. The flow diagram, material balance, control diagram, plot plan, layout, and elevation drawings are shown in figures 26-30 for the integrated base case. Layout and elevation drawings for a Cat-Ox reheat unit are presented in figures 31 and 32. A description of the processing areas is given.

Startup Bypass Ducts and Dampers

To prevent contaminating the catalyst and acid with fly ash during startup, the Cat-Ox process is equipped with


STARTUP BYPASS
BOILER
PRECIPITATOR
CONVERTERS
BFW TO STEAM PLANT
ECONOMIZER
PULVERIZED COAL
BOILER FEEDWATER FROM STEAM PLANT
STARTUP BYPASS
I D FAN
STACK
F D FAN
FLY ASH TO DISPOSAL
INTERMITTENT WASH
MIST ELIMINATOR
ABSORBER
AIR HEATER
PRODUCT ACID COOLER
WATER
PRODUCT STORAGE TANKS
TURBINE EXTRACTION STEAM
CONDENSATE TO STEAM PLANT
STEAM/AIR HEATER
NO 2 CIRCULATION ACID COOLER
TO TANK CAR/TRUCK
PUMP
TO STEAM PLANT
NO 1 CIRCULATION ACID COOLERS
CONDENSATE HEATER
PUMP
TRAP
CONDENSATE
FLUID/AIR HEATER
AIR

STREAM NO	1	2	3	4	5	6	7	8	9	10
DESCRIPTION	COAL TO BOILER	AIR TO FLUID/AIR HEATER	AIR TO STEAM/AIR HEATER	AIR TO AIR HEATER	COMBUSTION AIR TO F D FAN	FLUE GAS TO PRECIPITATOR	FLUE GAS TO CONVERTER	FLUE GAS TO ECONOMIZER	FLUE GAS TO AIR HEATER	FLUE GAS TO ABSORBER
RATE, LBS/HR	375M	1,130M	1,130M	1,130M	1,018M	1,101M	1,101M	1,101M	1,101M	1,212M
SCFM		246M	246M	246M	222M	234M	236M	236M	236M	260M
GPM										
PARTICULATES, LBS/HR						8,436	10	5	5	5
TEMPERATURE, °F		110	262	288	535	890	890	890	700	468
SPECIFIC GRAVITY										
VISCOSITY, CPS										
UNDISSOLVED SOLIDS, %										
pH										

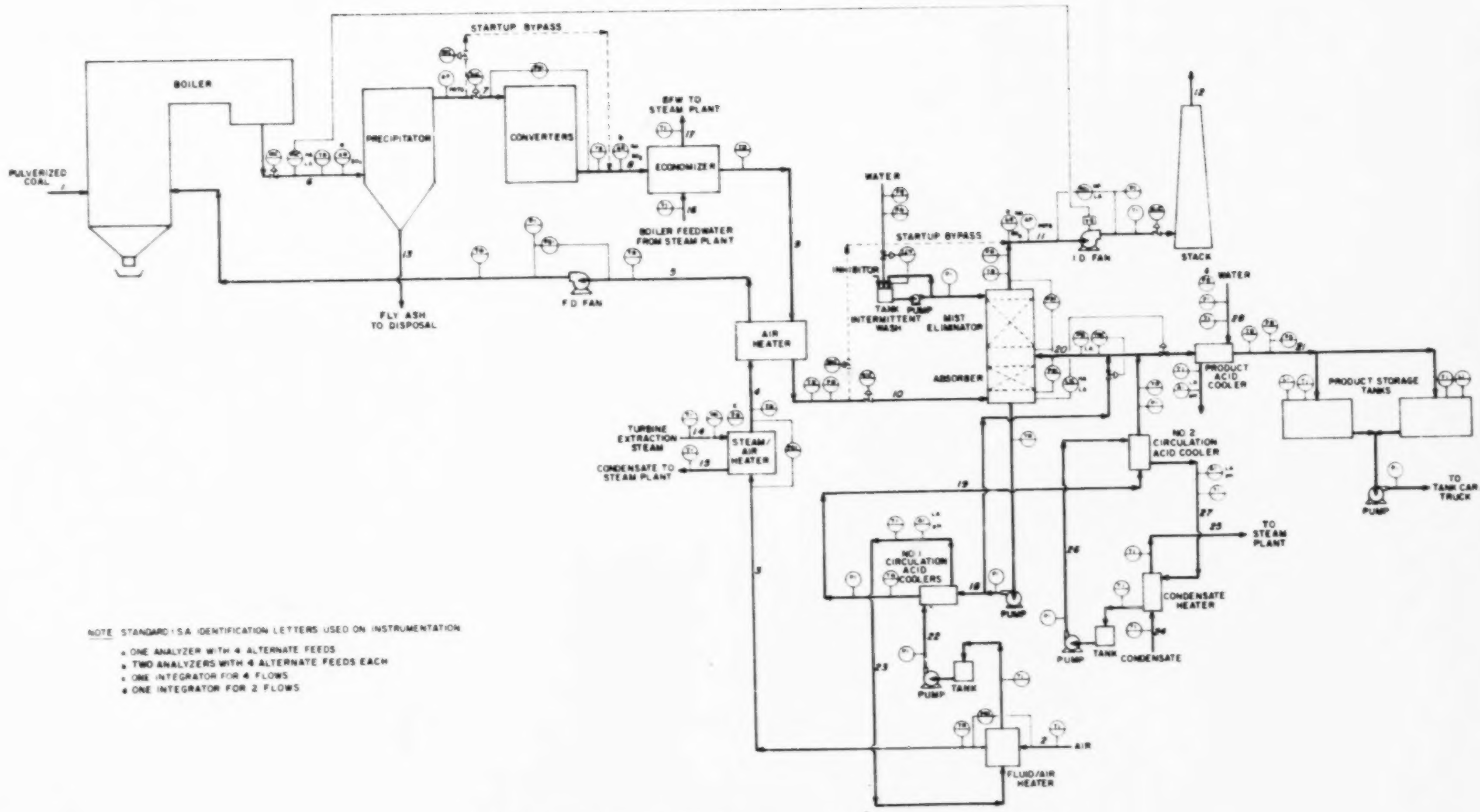
STREAM NO	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	FLUE GAS TO I D FAN	FLUE GAS TO ATMOSPHERE	FLY ASH TO DISPOSAL	STEAM TO STEAM/AIR HEATER	CONDENSATE TO STEAM PLANT	BOILER FEEDWATER TO ECONOMIZER	BOILER FEEDWATER TO STEAM PLT	ACID TO NO 1 CIRC ACID COOLER	ACID TO NO 2 CIRC ACID COOLER	ACID TO ABSORBER
RATE, LBS/HR	1,202M	4,808M	8,426	8,400	8,400	858M	858M	724M	1,449M	1,439M
SCFM	258M	1,032M								
GPM					12.9	1,719	1,719	906	1,778	1,764
PARTICULATES, LBS/HR										
TEMPERATURE, °F	243	234		775	582	580	584	294	232	180
SPECIFIC GRAVITY										
VISCOSITY, CPS										
UNDISSOLVED SOLIDS, %										
pH										

STREAM NO	21	22	23	24	25	26	27	28	
DESCRIPTION	ACID TO PRODUCT STORAGE	FLUID TO NO 1 CIRC ACID COOLER	FLUID TO FLUID/AIR HEATER	CONDENSATE TO CONDENSATE HEATER	CONDENSATE TO STEAM PLANT	WATER TO NO 2 CIRC ACID COOLER	WATER TO CONDENSATE HEATER	WATER TO PRODUCT ACID COOLER	
RATE, LBS/LB	40.3M	312M	625M	680M	680M	678M	678M	18.5M	
SCFM									
GPM	48	625	1,251	1,360	1,360	1,356	1,358	37.1	
PARTICULATES, LBS/HR	20								
TEMPERATURE, °F	100	215	283	110	162	145	197		
SPECIFIC GRAVITY	1.68								
VISCOSITY, CPS									
UNDISSOLVED SOLIDS, %									
pH									

NOTES
1 CALCULATIONS BASED ON
  a 3.5% SULFUR IN COAL (DRY)
  b 12% ASH COAL (AS FIRED)
  c 98% OF SULFUR IN COAL EVOLVES AS SO_2
  d 75% OF ASH IN COAL EVOLVES AS FLY ASH
  e 99.9% REMOVAL OF PARTICULATES TO PRECIPITATOR
  f 90% SO_2 REMOVAL
2 PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3 STREAM NUMBERS 2-11, 15-17, 19, 20 & 23-27 ARE ONE OF FOUR SIMILAR STREAMS
4 STREAM NUMBERS 18 AND 22 ARE ONE OF EIGHT SIMILAR STREAMS
5 STREAM NUMBER 28 IS ONE OF TWO SIMILAR STREAMS

SYMBOL IN TABLE
M .... THOUSAND

Figure 26. Catalytic oxidation process. Flow diagram and material balance—base case.



BOILER
PULVERIZED COAL
PRECIPITATOR
CONVERTERS
STARTUP BYPASS
BFW TO STEAM PLANT
ECONOMIZER
BOILER FEEDWATER FROM STEAM PLANT
FLY ASH TO DISPOSAL
F D FAN
AIR HEATER
TURBINE EXTRACTION STEAM
CONDENSATE TO STEAM PLANT
STEAM/AIR HEATER
WATER
INHIBITOR
STARTUP BYPASS
TANK
PUMP
INTERMITTENT WASH
MIST ELIMINATOR
ABSORBER
I D FAN
STACK
WATER
PRODUCT ACID COOLER
PRODUCT STORAGE TANKS
PUMP
TO TANK CAR/TRUCK
NO 2 CIRCULATION ACID COOLER
TO STEAM PLANT
CONDENSATE HEATER
CONDENSATE
TANK
PUMP
NO 1 CIRCULATION ACID COOLERS
PUMP
PUMP
TANK
AIR
FLUID/AIR HEATER
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

NOTE STANDARD ISA IDENTIFICATION LETTERS USED ON INSTRUMENTATION

a ONE ANALYZER WITH 4 ALTERNATE FEEDS
b TWO ANALYZERS WITH 4 ALTERNATE FEEDS EACH
c ONE INTEGRATOR FOR 4 FLOWS
d ONE INTEGRATOR FOR 2 FLOWS

Figure 27. Catalytic oxidation process. Control diagram—base case.

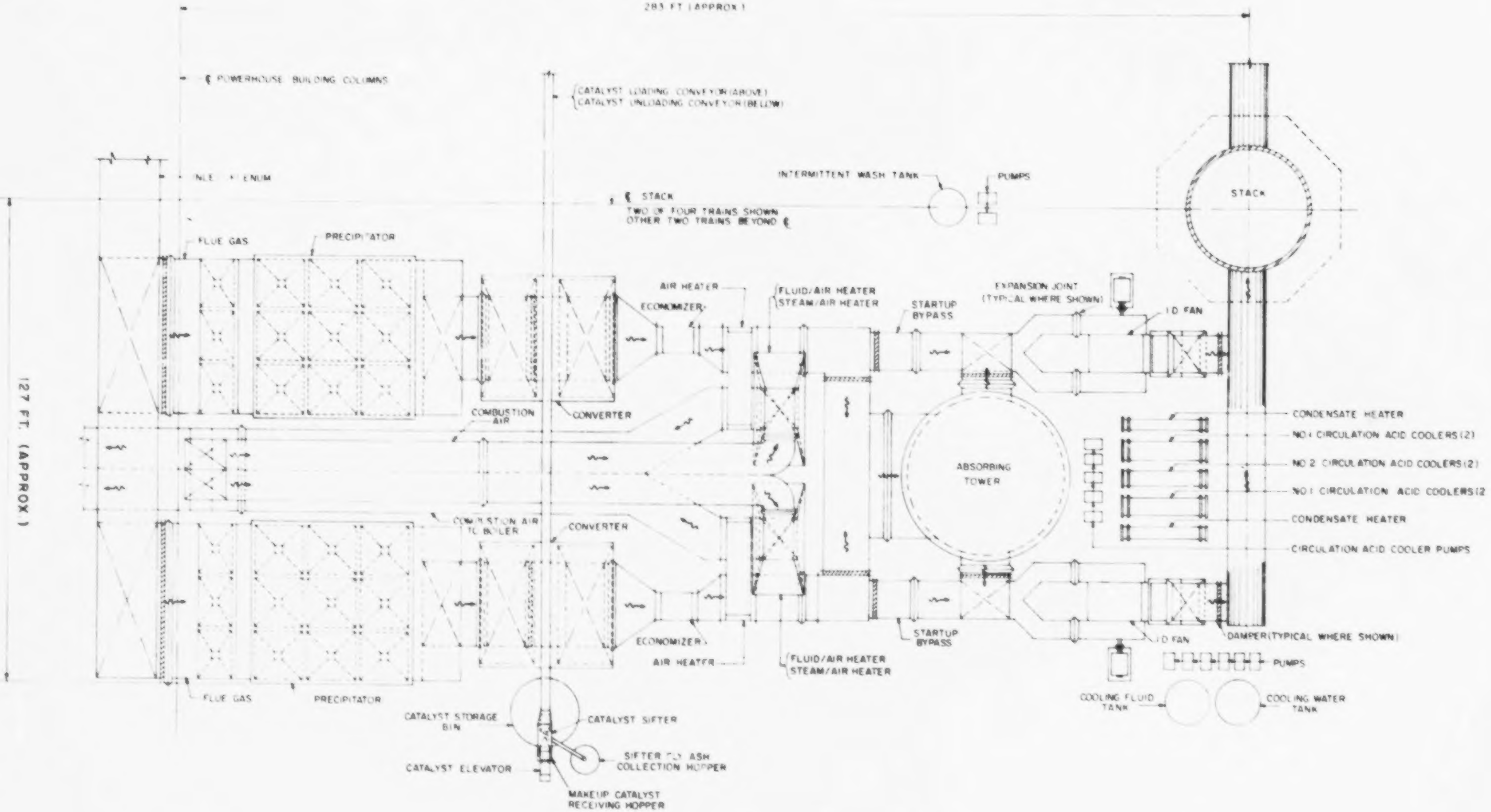

283 FT (APPROX.)
℄ POWERHOUSE BUILDING COLUMNS
CATALYST LOADING CONVEYOR (ABOVE)
CATALYST UNLOADING CONVEYOR (BELOW)
INLET PLENUM
℄ STACK
TWO OF FOUR TRAINS SHOWN
OTHER TWO TRAINS BEYOND ℄
INTERMITTENT WASH TANK
PUMPS
STACK
FLUE GAS
PRECIPITATOR
AIR HEATER
ECONOMIZER
FLUID/AIR HEATER
STEAM/AIR HEATER
STARTUP BYPASS
EXPANSION JOINT (TYPICAL WHERE SHOWN)
I.D. FAN
127 FT. (APPROX.)
COMBUSTION AIR
CONVERTER
ABSORBING TOWER
CONDENSATE HEATER
NO.1 CIRCULATION ACID COOLERS (2)
NO.2 CIRCULATION ACID COOLERS (2)
NO.1 CIRCULATION ACID COOLERS (2
CONDENSATE HEATER
CIRCULATION ACID COOLER PUMPS
COMBUSTION AIR TO BOILER
CONVERTER
ECONOMIZER
AIR HEATER
FLUID/AIR HEATER
STEAM/AIR HEATER
STARTUP BYPASS
I.D. FAN
DAMPER (TYPICAL WHERE SHOWN)
PUMPS
COOLING FLUID TANK
COOLING WATER TANK
FLUE GAS
PRECIPITATOR
CATALYST STORAGE BIN
CATALYST SIFTER
CATALYST ELEVATOR
SIFTER FLY ASH COLLECTION HOPPER
MAKEUP CATALYST RECEIVING HOPPER

Figure 28. Catalytic oxidation process. SO_2 conversion and absorption system layout - plan - base case.

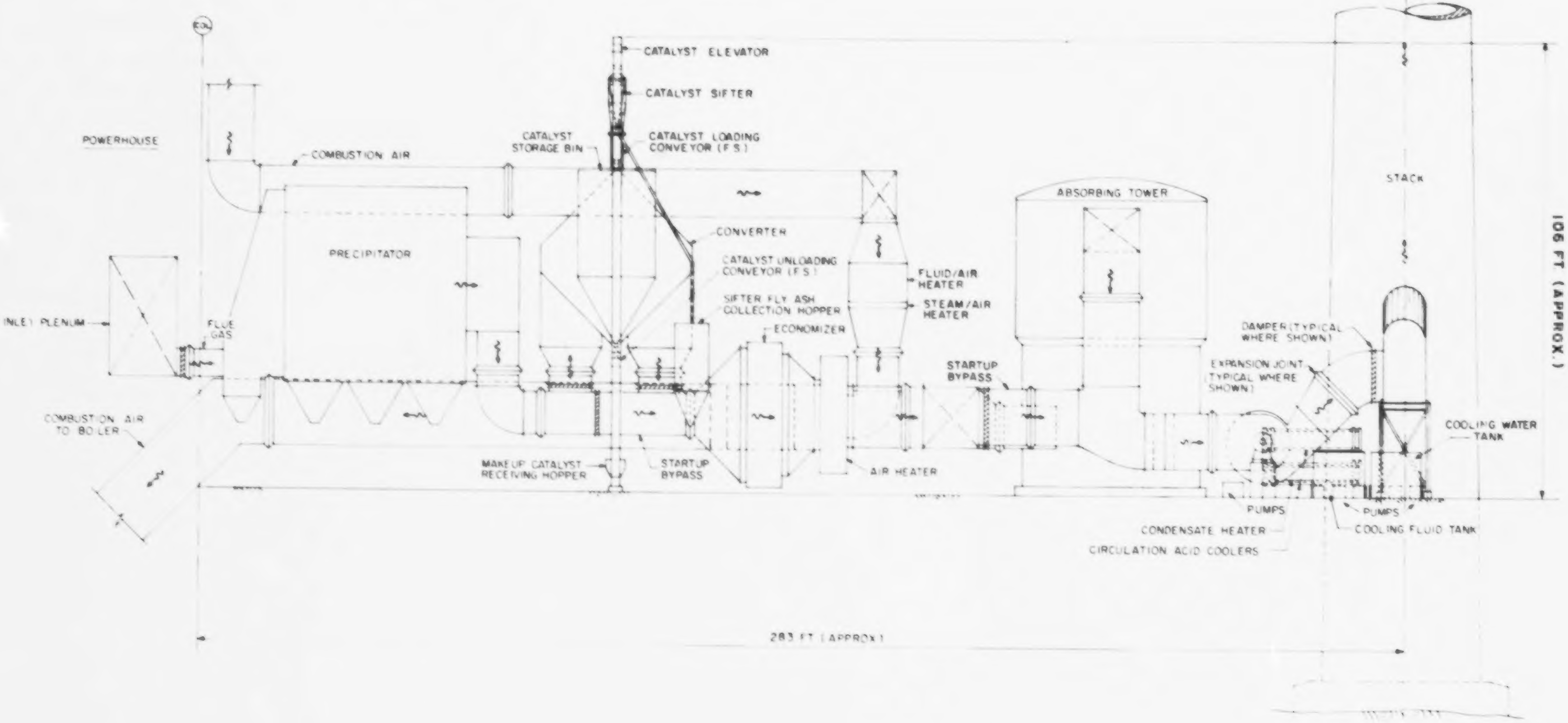

CATALYST ELEVATOR
CATALYST SIFTER
POWERHOUSE
CATALYST STORAGE BIN
CATALYST LOADING CONVEYOR (F.S.)
COMBUSTION AIR
ABSORBING TOWER
STACK
106 FT (APPROX.)
CONVERTER
PRECIPITATOR
CATALYST UNLOADING CONVEYOR (F.S.)
FLUID/AIR HEATER
STEAM/AIR HEATER
INLET PLENUM
FLUE GAS
SIFTER FLY ASH COLLECTION HOPPER
ECONOMIZER
DAMPER (TYPICAL WHERE SHOWN)
EXPANSION JOINT (TYPICAL WHERE SHOWN)
STARTUP BYPASS
COMBUSTION AIR TO BOILER
COOLING WATER TANK
MAKEUP CATALYST RECEIVING HOPPER
STARTUP BYPASS
AIR HEATER
PUMPS
PUMPS
CONDENSATE HEATER
COOLING FLUID TANK
CIRCULATION ACID COOLERS
283 FT (APPROX.)

Figure 29. Catalytic oxidation process. SO_2 conversion and absorption system layout–elevation–base case.

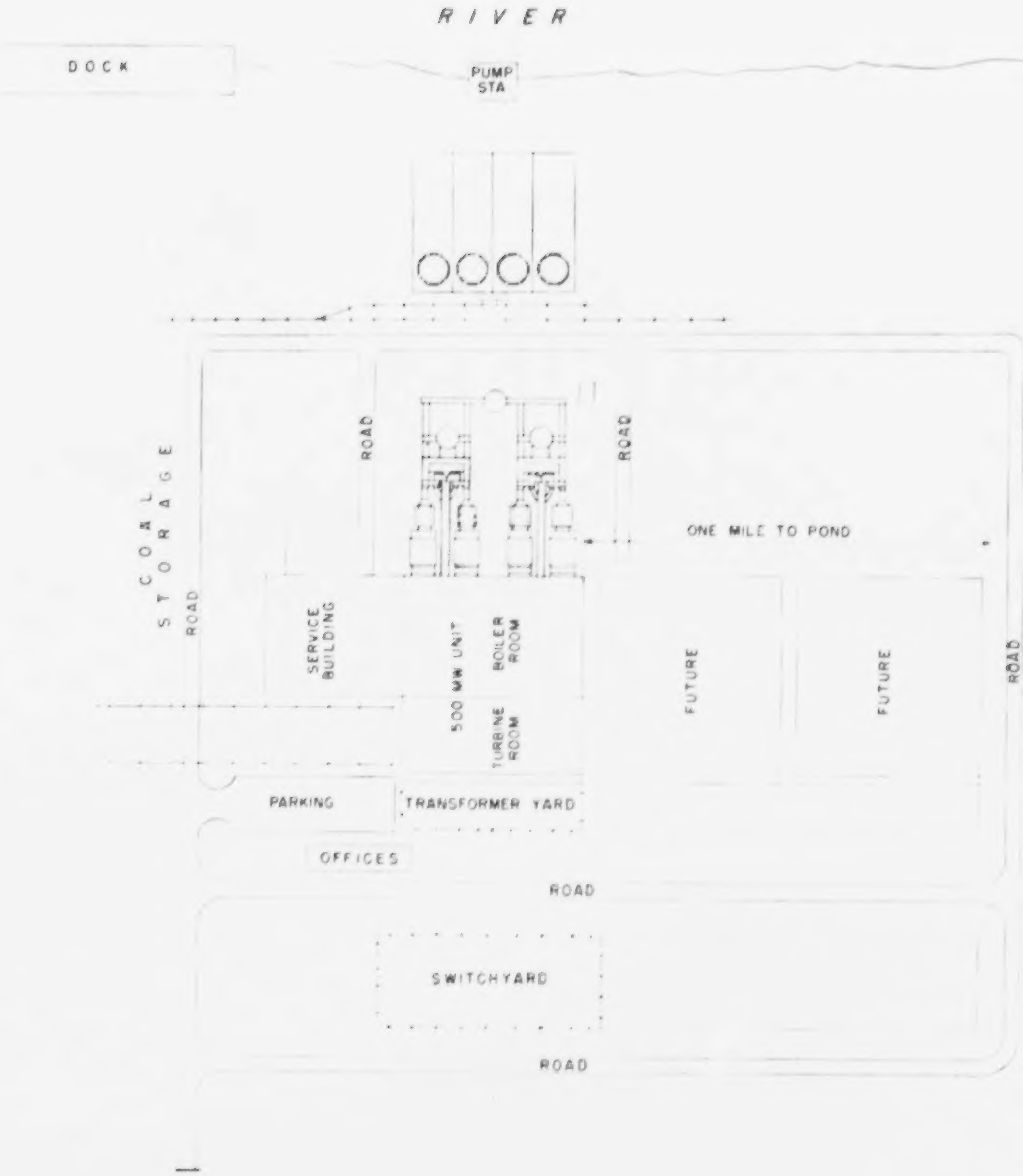

RIVER
DOCK
PUMP STA
COAL STORAGE
ROAD
ROAD
ROAD
SERVICE BUILDING
500 MW UNIT
BOILER ROOM
TURBINE ROOM
ONE MILE TO POND
FUTURE
FUTURE
ROAD
PARKING
TRANSFORMER YARD
OFFICES
ROAD
SWITCHYARD
ROAD

Figure 30. Catalytic oxidation process. Overall plot plan—base case.

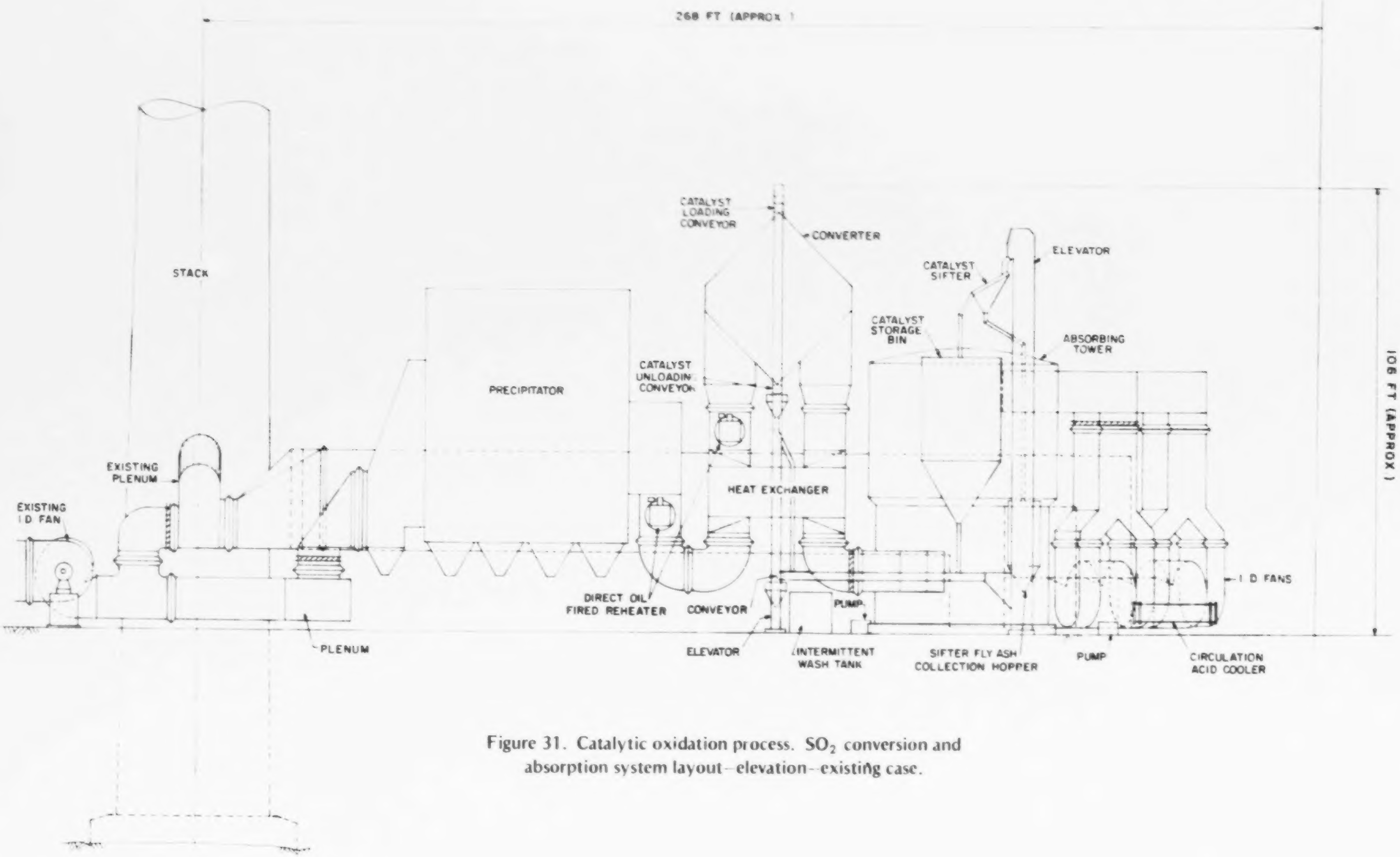

268 FT (APPROX.)
106 FT (APPROX.)
STACK
EXISTING PLENUM
EXISTING I.D. FAN
PLENUM
PRECIPITATOR
CATALYST UNLOADING CONVEYOR
DIRECT OIL FIRED REHEATER
CONVEYOR
ELEVATOR
CATALYST LOADING CONVEYOR
CONVERTER
HEAT EXCHANGER
PUMP
INTERMITTENT WASH TANK
CATALYST STORAGE BIN
CATALYST SIFTER
ELEVATOR
ABSORBING TOWER
SIFTER FLY ASH COLLECTION HOPPER
PUMP
I.D. FANS
CIRCULATION ACID COOLER

Figure 31. Catalytic oxidation process. SO_2 conversion and absorption system layout–elevation–existing case.

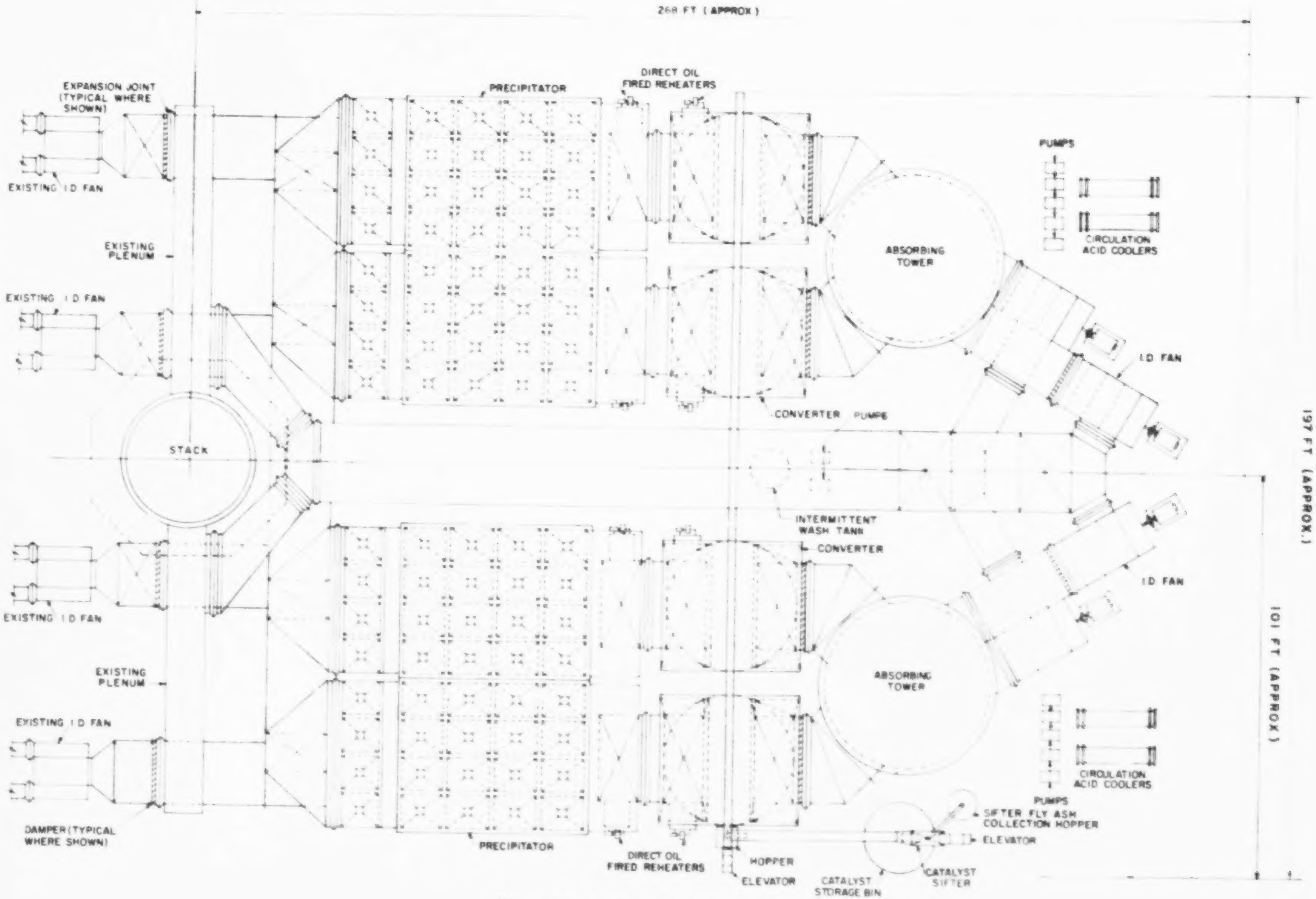

268 FT (APPROX)
EXPANSION JOINT (TYPICAL WHERE SHOWN)
PRECIPITATOR
DIRECT OIL FIRED REHEATERS
PUMPS
CIRCULATION ACID COOLERS
ABSORBING TOWER
EXISTING I D FAN
EXISTING PLENUM
EXISTING I D FAN
I D FAN
CONVERTER
PUMPS
197 FT (APPROX.)
STACK
INTERMITTENT WASH TANK
CONVERTER
I D FAN
101 FT (APPROX)
EXISTING I D FAN
ABSORBING TOWER
EXISTING PLENUM
EXISTING I D FAN
CIRCULATION ACID COOLERS
PUMPS
SIFTER FLY ASH COLLECTION HOPPER
ELEVATOR
DAMPER (TYPICAL WHERE SHOWN)
PRECIPITATOR
DIRECT OIL FIRED REHEATERS
HOPPER
ELEVATOR
CATALYST STORAGE BIN
CATALYST SIFTER

Figure 32. Catalytic oxidation process. SO_2 conversion system layout—plan—existing case.

Table 23. Electrostatic Precipitator Requirements—Catalytic Oxidation Process

Power unit		Removal efficiency		Gas temperature
Type	Status	Present	Additional	°F
Coal fired	New		99.9	890
Coal fired	Existing	98.7	92.3	310
Coal fired	Existing		99.9	310
Oil fired	New		84.4	890
Oil fired	Existing		84.4	310

startup bypass ducts. This area includes flue gas ducts and dampers that bypass the converters and absorbers during startup by routing the gas directly to the I.D. fan. Existing units use dampers at the tie-in to the existing power unit ducts to provide a startup bypass around the removal facilities.

Electrostatic Precipitators and Inlet Ducts

For both new and existing units, fly ash is removed by high efficiency electrostatic precipitators. Table 23 shows the electrostatic precipitator requirements to obtain 99.9% removal efficiency (equivalent to 0.005 gr/scf) required for operation of the Cat-Ox facilities.

Costs for the following flue gas distribution facilities are included in this area:

1. One inlet flue gas plenum interconnecting each of the four flue gas ducts.
2. Four flue gas ducts between the inlet plenum and the electrostatic precipitators, including one damper per duct.
3. Four flue gas ducts between electrostatic precipitators and converters (one-half of cost is included in this area; the other half is included in the SO_2 conversion area).

Existing coal-fired and oil-fired units have four flue gas ducts between the power unit I.D. fan outlet and the inlet plenum in addition to the flue gas distribution facilities described above.

Sulfur Dioxide Converters and Ducts

The following equipment is provided:

1. Four flue gas ducts between the electrostatic precipitators and converters (one-half of cost is included in this area; the other half is included in the electrostatic precipitator area).
2. Four 36-ft-long x 33-ft-wide x 50-ft-high converters including platework, screens, insulation, catalyst discharge gates, platforms, and paint.
3. One 5-hp enclosed belt conveyor (catalyst unloading).
4. One 25-hp enclosed belt conveyor (catalyst loading).
5. One 10-hp catalyst elevator.
6. One 10-ft-long x 4-ft-wide, 3-hp catalyst sifter with single deck screen.
7. One 938-ft^3 fly ash collection hopper with closed top.
8. One 7,634-ft^3 catalyst storage bin with closed top.
9. Thirty-three pneumatic control knife gate valves and 32 hand-operated knife gate valves.
10. One 2-ft-long x 2-ft-wide x 75-ft-high catalyst convolute cascade chute.
11. Four flue gas ducts between the converters and economizers (one-half of cost is included in this area; the other half is included in the heat recovery area). For existing units, flue gas ducts between the converters and absorbers are included (one-half of cost is included in this area, the other half is included in the sulfuric acid absorbers and coolers area).

Heat Recovery and Ducts

For energy conservation purposes, this area includes facilities for recovering heat from the hot combustion gases downstream of the boiler and preheating combustion air before it enters the boiler. The following equipment is provided:

1. Four 8-ft-long x 7-ft-wide x 33-ft-high finned-tube, gas-to-water economizers. (The costs of these economizers are not included in the investment estimate as they are required by the power unit without removal facilities. Although finned-tube economizers offer a potential savings over the conventional bare tube-type, additional housing costs are incurred as a result of locating the economizer outside of the boiler building; therefore, an investment credit was not claimed.)
2. Four 27-ft-long x 24-ft-wide x 7-ft-high gas-to-air Ljungstrom air heaters (smaller air heaters and less ductwork are required than with normal power units; therefore, a credit is received from the power plant for these facilities).
3. Four finned-tube steam/air heaters contained in a 2-ft-long x 30-ft-wide x 14-ft-high housing.
4. Four finned-tube fluid/air heaters contained in a 9-ft-long x 30-ft-wide x 14-ft-high housing.
5. Four 4,034-ft^2, shell and tube condensate heaters.
6. Two 8,140-gal cooling water surge tanks.
7. Six 1,356-gpm, 100-hp, single-stage, horizontal, split-case, centrifugal cooling water recirculation pumps (4 operating and 2 spare).
8. Four flue gas ducts between the converters and economizers (one-half of cost is included in this

area; the other half is included in the SO_2 converter area).

9. Four flue gas ducts between the economizers and air heaters.
10. Four combustion air ducts between the powerhouse and air heaters.
11. Four combustion air ducts between air heaters and F.D. fan (one-half of cost is included in this area; the other half is included in the fan area).

New oil-fired units are equipped with direct oil-fired heaters to replace the steam air heaters. Existing coal- and oil-fired units include eight direct oil-fired reheaters and four gas-to-gas heat exchangers to reheat the flue gas to 890 F prior to conversion and to recover the heat after conversion.

Fans

Fan location, method of costing, and duct configuration for the catalytic oxidation process are similar to that described for the limestone slurry process with the exception of pressure drop and supplemental fan location for existing power units. Existing units for Cat-Ox use supplemental I.D. fans downstream of the absorbers instead of supplemental F.D. fans in series with the power unit fans as provided for the other processes. Table 24 identifies the pressure drop distribution provided for each of the various designs.

The base case investment and operating cost estimates include the following:

1. Incremental costs for four 3,750-hp (46 in. ΔP) I.D. fans prorated to 31 in. of pressure drop attributed to particulate and SO_2 removal.
2. Four exit flue gas ducts between the I.D. fans and the stack gas plenum.

For existing units, this area includes the ductwork between the new I.D. fans downstream of the absorbers and the tie-in to the existing plenum.

Sulfuric Acid Absorbers and Coolers

The following equipment is provided:

1. Two vertical, cylindrical lead line absorbers including 3 in. ceramic packing, and Brink fiber demisters.
2. Ten 900-gpm, 60-hp, horizontal, centrifugal, high silicon-iron acid circulation pumps (8 operating and 2 spare).
3. Eight 12,200-ft² shell and tube acid-to-fluid heat exchangers (No. 1 circulation acid coolers) with impervious graphite tubes.
4. Two 7,510-gal coolant fluid surge tanks.
5. Six 1,250-gpm, 125-hp, single-stage, horizontal, split case, centrifugal coolant recirculation pumps (4 operating and 2 spare).
6. Four 8,070-ft² shell and tube acid-to-water heat exchangers (No. 2 circulation acid coolers) with impervious graphite tubes.
7. Two 165-ft² shell and tube acid-to-water heat exchangers (product acid coolers) with impervious graphite tubes.
8. One 8,000-gal intermittent wash tank.
9. Two 800-gpm, 40-hp, single-stage, horizontal, split-case, centrifugal, intermittent wash pumps (1 operating and 1 spare).
10. Four flue gas ducts between air heater and I.D. fan inlet.

Existing coal- and oil-fired units do not have the heat recovery circulation loops; the following equipment is provided for existing units.

1. Two absorbers and mist eliminators (same as for new units).
2. Ten 900-gpm, 60-hp horizontal, centrifugal, high silicon iron acid circulation pumps (8 operating and 2 spare).
3. Four 5,330-ft² shell and tube acid-to-water heat exchangers (circulation acid-coolers) with impervious graphite tubes.
4. Two 165-ft² shell and tube acid-to-water heat exchangers (product acid coolers) with impervious graphite tubes.
5. One 8,000-gal intermittent wash tank.
6. Two 800-gpm, 40-hp, single-stage, horizontal, split-case, centrifugal, intermittent wash pumps (1 operating and 1 spare).
7. Four flue gas ducts between converters and absorbers (one-half of cost is included in this area; the other half is in the SO_2 converter area).
8. Four flue gas ducts between the absorbers and the inlet to the supplemental I.D. fan.

Table 24. Assumed Pressure Drop Distribution for Specification of Fans Catalytic Oxidation Process

Power unit			Pressure drop distribution, inches H_2O attributed to		
Fuel	Status	SO_2 removal efficiency, %	Power production	SO_2 removal	Total
Coal	New	90	15.0	31.0[b]	46.0
Coal	Existing	90	a	39.5[b]	39.5
Oil	New	90	15.0	29.0[b]	44.0
Oil	Existing	90	a	39.5[b]	39.5
Coal (without existing ESP)	Existing	90	a	39.5[b]	39.5

[a] Existing power units already have fans which overcome the pressure drop attributed to power production.

[b] Includes pressure drop attributed to both particulate and SO_2 removal.

Sulfuric Acid Storage and Shipping

This area is similar to the magnesia slurry - regeneration process sulfuric acid storage and shipping area with the exception that one additional 500,000-gallon storage tank is provided to allow for storage of the lower concentration acid. A list of the equipment included in the estimate is given in the magnesia slurry - regeneration process sulfuric acid storage and shipping area.

Utilities

Facilities for the generation and distribution of utilities for the Cat-Ox process are similar to the limestone slurry process with two exceptions. For the Cat-Ox process, the steam supply system is included in the heat recovery area and the cooling water system is included in the sulfuric acid absorbers and coolers area. The other equipment included in the estimate is similar to that included in the limestone slurry process utilities area.

Service Facilities

This area includes the following items:

1. Vehicles allocation to power unit for use of plant vehicles.
2. Building and equipment One 5,000-ft^2 maintenance and instrument shop; allocation to power unit for one 1,800-ft^2 building, including process and motor control facilities, laboratory, lockers, offices, restrooms; allocation to power unit for one 2,000-ft^2 stores area.
3. Railroads costs for 1,000 ft of track, 1 switch, and 1 car puller.
4. Parking lot, walkways, and approximately 1 mile of paved roads.
5. Landscaping, fencing, and security.

Units with direct oil-fired reheat systems include an additional 800 feet of railroad track and two switches in this area for fuel oil receiving and handling.

Construction Facilities

Construction facilities are projected as 5% of the subtotal area investments similar to the method used for the limestone slurry process.

Economic Evaluation And Comparison

Based on the very definitive power plant, process design, and economic premises previously outlined and the specific equipment and installation requirements of each process as described in the previous section, generalized capital investment and operating cost estimates, both annual, and lifetime, are prepared for economic evaluation and comparison of the five processes. For "state of the art" estimating purposes, the representative designs are assumed to be proven (not first of a kind); however, it is recognized that the current development and demonstration status of these five processes does not justify such an assumption. Further testing and operating experience may in time invalidate the results of this economic appraisal, however, it is presently believed that inflation will now be the primary cause of future cost changes rather than advancements in technical knowledge as in the past.

Although this exercise is probably the most intensive effort, thus far, to predict, compare, and publish the investment and operating costs of several stack gas SO_2 removal systems, the generalized results derived will still not cover all the possible power plant, process design, economic variations, configurations, and combinations which will be encountered in applications of these five processes. Hopefully, the procedures used to prepare and present this evaluation are sufficiently comprehensive, visible, and modular to permit easy alteration of results to fit the many possible specific applications. The procedures used to project and display the process investment and operating costs are described below and the results of analysis follow. Also, sensitivity analyses have been performed to evaluate the effect of variation from the assumed value of key inputs on control costs.

PROCEDURES

To provide highly visible, well-defined, and readily comparable results of the economic evaluation, four different methods are used for displaying capital investment estimates. Three displays are used for presenting annual operating costs with two others used for presenting lifetime operating costs. A regulated private utility-type costing is used for the process evaluation (14). The procedures for projecting and displaying the results are discussed below.

Capital Investment

The projected capital investment estimates correspond to a midwestern power plant location and a 3-year construction schedule beginning mid-1972, ending mid-1975, with an expected midpoint of project expenditures of mid-1974. The mid-1974 costs assume the following estimated *Chemical Engineering* (58) indices: equipment machinery and supports 153.8; construction labor 177.9; overall CE plant cost index 160.2. The projected indices correspond to annual overall escalation rate for equipment machinery and supports, and construction labor varying from 4.0% to 10.0% per year.

Each of the four methods of projecting investment and displaying results, and the many considerations involved are discussed below.

1. *Base case equipment list and cost tables* Major process equipment costs which are illustrated in tables 46-50 and incorporated into each estimate are derived from either budgetary estimates obtained through extensive contacts with vendors, or actual costs for similar process equipment purchased by TVA. Authoritative publications (4, 21, 23, 33, 34, 39) on estimating are used for costs of the minor items such as tanks and pumps. A detailed table describing the base case equipment and costs, exponential factors used for size scaling, and the source of the base case cost data is presented for each process. **Table 46, page 101** in the "Results" section of the report illustrates the method for presenting the base case equipment description and cost data for the limestone slurry process. The base costs indicated in each of the tables (46-50) correspond to the equipment described. The size-cost scale factors are typical values indicated in the literature; where more than one scale factor is indicated, the factor from the latest cost reference is used for scaling from the base to other equipment sizes. Accuracy of the various cost sources is projected below (see pp. 157-165).

Source of data	Accuracy, % variance
Vendor data	+20, -10
Previous purchases, escalated	+10, -10
Publications	+30, -20

2. *Total capital investment requirements base case and existing case process equipment and installation*

analysis. For illustrative purposes, the process equipment and installation analysis for the base case and existing case of each of the five processes are shown in tables 35-44. These display tables show summarized area-by-area equipment costs along with installation expense including costs for piping, ductwork, concrete, excavation and site preparation, structures, electrical equipment, instrumentation, painting, buildings, land, and construction facilities. Installation expenses are estimated individually based on detailed layout drawings, itemized material take offs and projected erection labor requirements and are itemized separately and displayed according to the material and labor component of each, where applicable. The subtotal direct investment is defined as the sum of the above costs for each area.

To the subtotal direct investment is added the indirect costs for the project, which include engineering design and supervision, construction field expense, and contractor fees and contingency.

Each of these indirects is estimated as a percentage of the direct investment as specified in the power plant, process design, and economic premises (see table 10). The subtotal fixed investment is defined as the sum of the subtotal direct investment and the indirects.

In keeping with the FPC accounting practice, allowances are included for startup and modifications and interest during construction at 8% per year as discussed previously. These allowances are estimated as a percentage of the subtotal fixed investment and added to the subtotal fixed investment to obtain the total capital investment.

3. *Summary of estimated fixed investment—area-by-area investment cost breakdown for each of the 16 case variations studied.* In addition to the more detailed base case and existing case total capital investment breakdown tables which are presented in the text, a summary of estimated fixed investment is presented in Appendix B for each of the projected case variations. Examples can be seen in Appendix tables B-1, B-4, B-7, etc. The method used for projecting these estimates is discussed in the following paragraphs.

Excluding construction facilities for each area, the base case direct cost shown in tables 35, 37, 39, 41, 43 are broken into the material and labor components and adjusted as necessary to reflect required modifications in process design for the case variations. For example, indirect steam reheat investment costs are replaced with direct oil-fired reheat investment costs for existing coal-fired and all oil-fired units requiring stack gas reheat, and investment costs for an additional scrubbing bed are included for limestone scrubbing systems which do not utilize a particulate scrubber (existing coal-fired units and new and existing oil-fired units). Modifications are included in the amount of ductwork provided for all existing units.

The labor portion of the area investments for existing units is estimated by multiplying the projected labor requirements for a new unit of equivalent design by a retrofit difficulty factor of 1.25. This factor corresponds to an assumed labor efficiency of 80% for retrofit installations. The adjusted subtotal area investment is then scaled exponentially according to the relative throughput, using a weighted average scaling exponent calculated from the base case investment breakdown. Flue gas processing areas are scaled on the basis of relative gas throughput whereas byproduct processing areas are scaled on the basis of relative sulfur throughput. Table 25 shows the relative quantities of gas and sulfur which must be processed for each of the case variations, in comparison to the base case quantities. Once these area investments are scaled and construction facilities are reincorporated into the estimate, the subtotal direct, subtotal fixed, and total capital investment are determined by the same procedure described above for the base case investment.

Table 25. Relative Quantities of Gas and Sulfur to be Processed in Comparison with the Base Case Quantities

Case	Relative throughput rate, %	
Coal-fired power unit	Gas	Sulfur removed
90% SO_2 removal		
200 MW N 3.5% S	40.89	40.89
200 MW E 3.5% S	42.22	42.22
500 MW E 3.5% S	102.22	102.22
500 MW N 2.0% S	100.00	57.14
500 MW N 3.5% S	100.00	100.00
500 MW N 5.0% S	100.00	142.86
1,000 MW E 3.5% S	200.00	200.00
1,000 MW N 3.5% S	193.33	193.33
80% SO_2 removal		
500 MW N 3.5% S	100.00	88.89
Oil-fired power unit		
90% SO_2 removal		
200 MW N 2.5% S	34.44	21.81
500 MW N 1.0% S	84.23	21.33
500 MW N 2.5% S	84.23	53.33
500 MW N 4.0% S	84.23	85.33
500 MW E 2.5% S	86.00	54.52
1,000 MW N 2.5% S	162.89	103.10

As an illustration of the use of this method, the direct cost for the raw material handling area for the limestone slurry process from table 35 is \$419,000, of which \$198,000 is material costs, and \$221,000 is labor. Assuming a retrofit difficulty factor of 1.25, the total area investment for an existing unit of similar capacity is \$198,000 plus 1.25 (\$221,000), or \$474,000. Using a weighted average scaling exponent of 0.65 for the limestone process raw material handling area and a relative limestone throughput rate of 42.22% for a 200-MW existing power unit, as indicated in table 25, the projected raw material handling area costs for this unit is \$271,000 as shown in Appendix table B-4.

4. *Total capital investment requirements—tabular investment results of the 16 case variations*—For each of the five processes, a summary table is presented in the text giving the projected total capital investment requirements for the case variations, expressed as total \$ and \$/kW as illustrated in tables 27-31.

Operating Costs

Annual and lifetime operating costs for each process are presented on a regulated economics basis. The basic premise of regulated economics provides that the power company will be permitted to charge electricity customers sufficiently to earn up to a prescribed return on the base investment. Since electrical power producers rarely compete with each other in a given geographical area, regulation of power rates is necessary to prohibit unreasonable profits, but at the same time assure an adequate return on investment sufficient to attract capital for expansion to meet growing demand. In the United States, regulation is usually the responsibility of state or local agencies with the FPC responsible for setting guidelines for accounting procedures and for rates on interstate transactions (14).

If a power company provides all or a portion of the investment for pollution abatement facilities, its investment will almost certainly be merged with the total power plant investment as is presently done with dust removal equipment and, therefore, increase the "rate base" on which the utility is allowed to earn at the rate set by the regulatory commission. Thus, a return on equity or profit must be included in any process evaluation under regulated economics; it is the "cost of investment money" as any other operating cost item such as fuel or labor.

The regulated "cost of investment money" is added to operating costs as part of the capital charges applied (see "Power Plant, Process Design, and Economic Premises").

In the projection of annual operating costs, capital charges are applied as average annual costs as defined in the economic premises. In the lifetime operating cost projections, however, declining balance capital charges based on the undepreciated investment are applied, similar to the actual method used in regulated industry. The methods for presenting annual and lifetime operating costs for the five processes are discussed below.

Annual Operating Cost

Annual operating costs are estimated under regulated economics assuming an overall cost of money of 10%. The operating life of the SO_2 control facilities is designed to be the same as the remaining life of the power plant. All tabulated results and operating cost tables correspond to mid-1975 costs, an annual operation of 7,000 hours, and straight line depreciation over the estimated power plant life. Operating costs for disposal of fly ash are not included in the annual operating cost estimates nor is product revenue reflected. To provide visibility of the results, the projected annual operating costs are presented in three manners. The method of projecting each of these operating cost estimates follows.

1. *Detailed area-by-area base case and existing case operating cost breakdown analyses*—For illustrative purposes, base case and existing case operating cost estimates for the five processes are presented in tables 59-68. Each of the operating cost estimates are subdivided by operating area function and projected according to the direct and indirect cost components. Included as direct costs are: delivered raw materials, operating labor and supervision, utilities, maintenance, and analyses. The indirect costs include capital charges, and plant and administrative overhead.

   Direct costs. The raw material costs given in the power plant, process design, and economic premises are projected 1975 delivered costs to a Chicago power plant location, and labor costs are projected 1975 midwestern rates. The projected costs of utilities to the process depend on quantity, source, and accounting practice. The values used are fully allocated costs, as if purchased from an independent source with full capital recovery provided for. As quantities increase, the unit cost of utilities is decreased to show some economy of scale. For those cases where a heat credit is taken for export of steam or heated boiler feed water to the power unit system, the value of the credit is based only on the equivalent fuel cost. For existing power units, it is assumed that steam is not available from the power plant.

   The quantities of raw materials and utilities required for each process, except for electricity, are shown on the material balance for the base case process design. Electricity requirements are projected from required motor horsepower or known equivalent kilowatt usage as defined in the base case equipment description.

Operating labor and supervision for each process is estimated considering the amount of process equipment in each area and the difficulty of operation. Analysis labor estimates are based on the quantities of materials which must be analyzed to maintain quality control. Maintenance is estimated as a percent of the subtotal direct investment, as shown in table 13. The maintenance percentages projected for each of the five processes are based on individual estimates of maintenance requirements for the various processing steps from pilot plants and systems already in operation.

Indirect costs The capital charges included in the indirect operating costs are applied as average capital charges, including depreciation, interim replacements, insurance, cost of capital and taxes, and considering the remaining life of the power plant. Plant overhead is estimated as 20% of the subtotal conversion costs, which includes the projected costs for labor, utilities, maintenance, and analyses. Administrative overhead is estimated as 10% of operating labor for the throwaway processes. For the product-producing processes, administrative and marketing overhead is estimated individually for each process on the basis of an estimated relative difficulty in marketing the various products.

The detailed operating cost breakdown tables (59-68) are presented in the text in a modular fashion so that all of the direct or indirect cost components are shown, according to the processing area to which they are attributed. The equivalent total unit operating cost is expressed as dollars per ton coal burned, mills per kilowatthour, cents per million Btu heat input, and dollars per ton sulfur removed. The distribution of direct and indirect operating costs is given, expressed as a percent of the total annual operating cost.

2. *Total projected average annual operating cost* Summary tables showing the projected breakdown of the average annual operating cost are presented in Appendix B for 16 case variations studied on each process. Examples can be seen in Appendix tables B-2, B-5, B-8, etc. These tables summarize the overall process costs and present equivalent unit operating costs expressed as dollars per ton coal or barrel oil burned, mills per kilowatthour, cents per million Btu heat input, and dollars per ton sulfur removed. The distribution of operating cost components are given, expressed as a percent of the total annual operating cost. Working capital requirements for each of the 16 case variations are calculated based on the projected annual operating cost breakdown and shown on the operating cost tables presented in the appendix for each process. For the present study, working capital is defined as the total of 3 weeks of raw material costs, 7 weeks of direct operating costs, and 7 weeks of overhead costs as discussed on page 29.

   Raw materials and utilities for the case variations are scaled from the requirements indicated on the detailed base case and existing case operating cost breakdown analyses (tables 59-68). Utilities such as humidification water, reheat energy, and electricity for the fan are scaled proportional to the relative gas rate for the many case variations; whereas, raw materials and utilities such as absorbent, and electricity for the sulfur processing areas, are scaled proportional to the relative sulfur rate for the various cases. Annual costs for raw materials and utilities are then calculated by applying the unit costs to the annual usage rates.

3. *Tabular summary of projected annual operating costs* For the 16 case variations given in the text a tabular summary of projected annual operating costs is given for each process, as illustrated in tables 51-55, with projected costs expressed in total dollars and equivalent unit costs.

Lifetime Operating Cost

Because of the typical declining load of most power units over their life, lifetime operating costs are better measures of the overall process costs than are annual operating costs. Since annual operating costs vary each year as the rate base declines due to depreciation "write off" (the cost of money and income taxes are applied to undepreciated portion of investment) and with any changes in on-stream time of the power unit, it is desirable to have a year-to-year tabulation of annual operating costs and cumulative lifetime operating costs for any given case. For the most meaningful comparison which recognizes the time value of money, the declining annual operating costs for each process over the life of the plant should be discounted at the cost of money (10% for this study) to the initial year of operation. The total of these costs can be compared directly or can be converted to equivalent unit costs for comparison with the premium expected for low-sulfur fuels.

For each of the 16 case variations of the five processes evaluated, lifetime economics are projected corresponding to the declining operating profile established earlier. Examples can be seen in the lifetime cost projections given in Appendix tables B-3, B-6, B-9, etc. Year-by-year operating costs included in the lifetime cost projections are calculated by computer in the same manner as annual operating costs, with the exception that capital charges are based on the declining undepreciated investment. Since the regulated rate of investment profitability is included in the year-by-year projections of operating costs, any revenue received from sale of byproducts can be applied toward reducing these yearly costs. Therefore, the net increase or decrease in the cost of power to the consumer for each year of the power plant life is defined as the corresponding operating cost less the revenue resulting from sale of byproduct. For the limestone and lime processes which do not produce a salable product, the net annual increase or decrease in cost of power is equal to the total operating cost. For the other processes, however, the net annual increase or decrease in cost of power is less than the total operating cost by an amount equal to the revenue from the sale of byproduct acid or sulfur. Results of the lifetime economic projections are presented in the following two fashions:

1. Computer printouts of the detailed year-by-year cash flow analyses are given in Appendix B for each of the 16 case variations for each process. Examples can be seen in Appendix tables B-3, B-6, B-9, etc.
2. Tables 70-74 giving the summarized results are presented in the text.

In each presentation, the lifetime economic results are given for each process as both cumulative actual and cumulative discounted costs (discounted at the cost of money to the initial year). The results are also given as the lifetime average increase or decrease and the levelized increase or decrease in unit operating cost expressed as dollars per ton coal or barrels of oil burned, mills per killowatthour, cents per million Btu heat input, and dollars per ton sulfur removed. As the name implies, the lifetime average increase or decrease in unit operating cost is simply an average unit operating cost obtained by dividing the lifetime operating cost by the lifetime number of units, such as tons of coal burned. Levelized unit operating costs are obtained by dividing the discounted process costs over the life of the power unit by the discounted number of units. They are the more significant costs because they include the effect of time on both money and units of measure.

SENSITIVITY ANALYSES

Since many components of the investment and operating cost estimates can vary, the sensitivity of operating cost results to variations in several of the key economic parameters is evaluated. Table 26 identifies the parameters which are varied and the range of values which is studied. Each range is selected corresponding to deviations in design or costs which can be encountered. As an illustration, investment variations ranging from 70% to 130% of the projected investment are selected to indicate the effect of inaccuracies on overall process costs. Limestone and lime price variations illustrate the effect of rural or metropolitan plant location and corresponding low and high cost limestone or lime on overall process costs. Other variations such as antioxidant utilization and MgO or catalyst losses are selected to show the effect of design and operating variations of particular processes on projected costs. The effects of these variations on the projected annual and lifetime operating costs are presented in figures 51-67 and 75-93 of the results.

RESULTS

Capital Investment

Summaries of the case variations for each process are shown in Appendix B, and tabulated totals are presented below in tables 27 through 31.

For the comparisons to be fully understood, a review of the premises should be undertaken parallel to careful examination of the results. Overall, the fixed investment costs for four of the processes are relatively close with lime slurry investment requirements lowest for new coal-fired units and limestone slurry investment lowest for new oil-fired and existing coal-fired units. These results depend heavily on the predefined number and types of scrubbers specified for the various duties. The limestone, magnesia, and sodium processes require only one scrubber stage for SO_2 removal, whereas the lime process requires two. When particulate removal is not required, the lime process suffers in comparison to the other processes. Selection of scrubber types other than venturis for the lime process might eliminate this disparity.

As can be seen from the display tabulations, the investment requirements for the five process cases cover a wide range. The projected total investments for the limestone slurry process range from $8,263,000 ($41.3/kW) for a new 200-MW, 2.5% S oil-fired unit to $37,725,000 ($37.7/kW) for a new 1,000-MW, 3.5% S coal-fired unit; investments for the lime slurry process range from $9,482,000 ($47.4/kW) for a new 200-MW, 2.5% S oil-fired unit to $38,133,000 ($38.1/kW) for an existing 1,000-MW, 3.5% S coal-fired unit.

With some important exceptions, the investment requirements of the product-producing processes are generally greater than those of either the limestone or lime throwaway processes. Investments for the magnesia slurry - regeneration process, however, are very competitive with lime and limestone, ranging from $8,861,000 ($44.3/kW) for a new 200-MW, 2.5% S oil-fired unit to $38,865,000 ($38.9/kW) for a new 1,000-MW, 3.5% S coal-fired unit; those for the sodium solution - SO_2 reduction process range from $10,324,000 ($51.6/kW) for a new 200-MW, 2.5% S oil-fired unit to $47,721,000 ($47.7/kW) for an existing

Table 26. Sensitivity Variations Studied in the Economic Cost Projections

Item	Process	Annual operating cost		Lifetime operating cost	
		Base value	Range of variations	Base value	Range of variations
Investment	Five processes			100% of projected investment	70%-130%
Years remaining life	Limestone slurry process (existing unit)			200 MW—20 yr 500 and 1,000 MW—25 yr	15, 20, 25 yr
On-stream time	Five processes	7,000 hr/yr	0-7,000	Declining on-stream profile (see table 3)	Constant on-stream time, 5,000 and 7,000 hr/yr over life of plant
Labor costs	Magnesia slurry - regeneration process	100% of estimated labor requirement	100%-200%		
	Limestone slurry process and sodium solution - SO₂ reduction process			Annual escalation rate, 0%/yr	0%-7.5%
Cost of money	Five processes	Average capital charges, 14.9% of total investment	12%-24%	Cost of investment money, 10%	8%-12%
Raw material price-consumption	Limestone slurry process	Limestone price, $4/ton	$2-$8		
	Lime slurry process	Lime price, $20.50-$26.00/ton depending on plant size	$18-$34		
	Magnesia slurry - regeneration process	MgO losses, 1.8%/cycle	1.8%-20%		
	Sodium solution - SO₂ reduction process	Antioxidant utilization, design rate	0%-100%		
	Catalytic oxidation processes	Catalyst losses, 10%/yr	10%-60%		
Waste disposal	Limestone slurry process	Waste disposal cost, $4/ton of wet solids	$2-$8		
High-low projection	Limestone slurry process			Raw material cost, $4/ton	$2-$8
				Waste disposal cost, $4/ton of wet solids	up to $8
Product revenue	Magnesia slurry - regeneration process			Sulfuric acid revenue, $8/ton	$0-$32
	Sodium solution - SO₂ reduction process			Sulfur revenue, $25/short ton	$15-$40
	Catalytic oxidation process			Sulfuric acid revenue, $6/ton	$0-$30

Table 27. Limestone Slurry Process Total Capital Investment Summary[a]

Case	Investment	
Coal-fired power unit	$	$/kW
90% SO_2 removal; on-site solids disposal		
200 MW N 3.5% S 30 yr	13,031,000	65.2
200 MW E 3.5% S 20 yr	11,344,000	56.7
500 MW E 3.5% S 25 yr	23,088,000	46.2
500 MW N 2.0% S 30 yr	22,600,000	45.2
500 MW N 3.5% S 30 yr	25,163,000	50.3
500 MW N 5.0% S 30 yr	27,343,000	54.7
1,000 MW E 3.5% S 25 yr	35,133,000	35.1
1,000 MW N 3.5% S 30 yr	37,725,000	37.7
80% SO_2 removal; on-site solids disposal		
500 MW N 3.5% S 30 yr	24,267,000	48.5
90% SO_2 removal; off-site solids disposal		
500 MW N 3.5% S 30 yr	20,532,000	41.1
90% SO_2 removal; on-site solids disposal (existing unit requiring particulate scrubber)		
500 MW E 3.5% S 25 yr	29,996,000	60.0
Oil-fired power unit		
90% SO_2 removal; on-site solids disposal		
200 MW N 2.5% S 30 yr	8,263,000	41.3
500 MW N 1.0% S 30 yr	12,935,000	25.9
500 MW N 2.5% S 30 yr	15,473,000	30.9
500 MW N 4.0% S 30 yr	17,481,000	35.0
500 MW E 2.5% S 25 yr	18,657,000	37.3
1,000 MW N 2.5% S 30 yr	23,384,000	23.4

[a] Stack gas reheat to 175°F.
On-site disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table 28. Lime Slurry Process Total Capital Investment Summary[a]

Case	Investment	
Coal-fired power unit	$	$/kW
90% SO_2 removal; on-site solids disposal		
200 MW N 3.5% S 30 yr	11,749,000	58.7
200 MW E 3.5% S 20 yr	13,036,000	65.2
500 MW E 3.5% S 25 yr	26,027,000	52.1
500 MW N 2.0% S 30 yr	20,232,000	40.5
500 MW N 3.5% S 30 yr	22,422,000	44.8
500 MW N 5.0% S 30 yr	24,272,000	48.5
1,000 MW E 3.5% S 25 yr	38,133,000	38.1
1,000 MW N 3.5% S 30 yr	32,765,000	32.8
80% SO_2 removal; on-site solids disposal		
500 MW N 3.5% S 30 yr	21,586,000	43.2
90% SO_2 removal; off-site solids disposal		
500 MW N 3.5% S 30 yr	18,323,000	36.6
90% SO_2 removal; on-site solids disposal (existing unit requiring particulate scrubber)		
500 MW E 3.5% S 25 yr	26,090,000	52.2
Oil-fired power unit		
90% SO_2 removal; on-site solids disposal		
200 MW N 2.5% S 30 yr	9,482,000	47.4
500 MW N 1.0% S 30 yr	15,961,000	31.9
500 MW N 2.5% S 30 yr	18,148,000	36.3
500 MW N 4.0% S 30 yr	19,861,000	39.7
500 MW E 2.5% S 25 yr	21,817,000	43.6
1,000 MW N 2.5% S 30 yr	26,341,000	26.3

[a] Stack gas reheat to 175°F.
On-site disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

1,000-MW, 3.5% S coal-fired unit. For the catalytic oxidation process, the projected investments range from $13,069,000 ($65.3/kW) for a new 200-MW, 2.5% S oil-fired unit to $69,889,000 ($69.9/kW) for a new 1,000-MW, 3.5% S coal-fired unit.

The summarized investment results for the five processes are shown in figures 33 through 37 which indicate the effect of power unit size, and sulfur content of fuel on the total fixed investment for units of different fuel type and status (new or existing). Again caution should be exercised in comparing results for new and existing coal-fired units, since existing coal-fired units are assumed to be already equipped with 98.7% efficient electrostatic precipitators for collecting fly ash. The effects of similar variations on unit investment ($/kW) are given in figures 38 through 41.

Another point of interest is the difference in investment requirements of the various processes for 80% versus 90% SO_2 removal. For each of the processes excluding catalytic oxidation, investment and operating cost projections for 80% SO_2 removal are given, for comparison with the 90% SO_2 removal base case projection. For the catalytic oxidation process, it is reported to be difficult [illegible] impractical to limit SO_2 removal to 80%, since it is too difficult to design the converters for only 80% efficient conversion of SO_2 to SO_3. Therefore, an 80% SO_2 removal case is not evaluated for the catalytic oxidation process. Table 32 gives a comparison of the investment requirements for the other four processes.

An important consideration for existing power units is the assumption for this study that these units are already

Table 29. Magnesia Slurry - Regeneration Process Total Capital Investment Summary[a]

Case	Investment	
Coal-fired power unit	$	$/kW
90% SO_2 removal		
200 MW N 3.5% S 30 yr	14,139,000	70.7
200 MW E 3.5% S 20 yr	14,372,000	71.9
500 MW E 3.5% S 25 yr	26,026,000	52.1
500 MW N 2.0% S 30 yr	22,958,000	45.9
500 MW N 3.5% S 30 yr	26,406,000	52.8
500 MW N 5.0% S 30 yr	29,355,000	58.7
1,000 MW E 3.5% S 25 yr	38,717,000	38.7
1,000 MW N 3.5% S 30 yr	38,865,000	38.9
80% SO_2 removal		
500 MW N 3.5% S 30 yr	25,568,000	51.1
90% SO_2 removal (existing unit requiring particulate scrubber)		
500 MW E 3.5% S 25 yr	32,213,000	64.4
Oil-fired power unit		
90% SO_2 removal		
200 MW N 2.5% S 30 yr	8,861,000	44.3
500 MW N 1.0% S 30 yr	12,695,000	25.4
500 MW N 2.5% S 30 yr	16,080,000	32.2
500 MW N 4.0% S 30 yr	18,765,000	37.5
500 MW E 2.5% S 25 yr	20,376,000	40.8
1,000 MW N 2.5% S 30 yr	23,656,000	23.7

[a] Stack gas reheat to 175°F.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table 30. Sodium Solution - SO_2 Reduction Process Total Capital Investment Summary[a]

Case	Investment	
Coal-fired power unit	$	$/kW
90% SO_2 removal		
200 MW N 3.5% S 30 yr	16,198,000	81.0
200 MW E 3.5% S 20 yr	17,149,000	85.7
500 MW E 3.5% S 25 yr	31,208,000	62.4
500 MW N 2.0% S 30 yr	26,706,000	53.4
500 MW N 3.5% S 30 yr	30,491,000	61.0
500 MW N 5.0% S 30 yr	33,709,000	67.4
1,000 MW E 3.5% S 25 yr	47,721,000	47.7
1,000 MW N 3.5% S 30 yr	45,832,000	45.8
80% SO_2 removal		
500 MW N 3.5% S 30 yr	29,127,000	58.3
90% SO_2 removal (existing unit requiring particulate scrubber)		
500 MW E 3.5% S 25 yr	37,957,000	75.9
Oil-fired power unit		
90% SO_2 removal		
200 MW N 2.5% S 30 yr	10,324,000	51.6
500 MW N 1.0% S 30 yr	15,198,000	30.4
500 MW N 2.5% S 30 yr	18,949,000	37.9
500 MW N 4.0% S 30 yr	21,893,000	43.8
500 MW E 2.5% S 25 yr	24,445,000	48.9
1,000 MW N 2.5% S 30 yr	28,765,000	28.8

[a] Stack gas reheat to 175°F.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

capable of meeting EPA particulate emission standards. Since some units may not yet be equipped with electrostatic precipitators to maintain these emission levels, the costs for an existing unit requiring installation of particulate control facilities are also projected. Table 33 gives a comparison of the investment requirement for existing units requiring the additional facilities with those which are already capable of meeting the EPA particulate emission standard.

The most noticeable effect which may be seen from this table is the very small difference in the lime process investment for the two variations considered. Since a two-stage scrubbing system is provided for the lime process regardless of the particulate removal requirements, this result is inherent with the SO_2 removal equipment specified for this process.

The comparison between investment requirements for limestone and lime slurry processes designed for off-site and on-site waste solids disposal is shown in table 34. Investments for off-site disposal are approximately 18% lower than corresponding on-site disposal investments, primarily because of the savings in the cost of a waste disposal pond.

Detailed base case and existing case area equipment and installation breakdowns which give component costs for the five processes are shown in tables 35 through 44. In comparing the base case area equipment and installation breakdowns for the five processes, the predominant cost areas can be readily identified. Table 45 shows the contribution of the major cost areas to the total capital investment for each of the five processes. However, it should again be noted that process differences and the total projected investment must be given careful consideration in comparing the results. For the limestone and lime slurry processes, the particulate removal, SO_2 absorption and waste disposal areas require the greatest investment. The predominant cost areas of the magnesia slurry -

Table 31. Catalytic Oxidation Process Total Capital Investment Summary[a]

Case	Investment	
Coal-fired power unit	$	$/kW
90% SO_2 removal		
200 MW N 3.5% S 30 yr	19,537,000	97.7
200 MW E 3.5% S 20 yr	17,735,000	88.7
500 MW E 3.5% S 25 yr	37,907,000	75.8
500 MW N 2.0% S 30 yr	42,520,000	85.0
500 MW N 3.5% S 30 yr	42,736,000	85.5
500 MW N 5.0% S 30 yr	42,928,000	85.9
1,000 MW E 3.5% S 25 yr	62,913,000	62.9
1,000 MW N 3.5% S 30 yr	69,889,000	69.9
90% SO_2 removal (existing unit without existing particulate collection facilities)		
500 MW E 3.5% S 25 yr	43,816,000	87.6
Oil-fired power unit		
90% SO_2 removal		
200 MW N 2.5% S 30 yr	13,069,000	65.3
500 MW N 1.0% S 30 yr	28,067,000	56.1
500 MW N 2.5% S 30 yr	28,277,000	56.6
500 MW N 4.0% S 30 yr	28,449,000	56.9
500 MW E 2.5% S 25 yr	32,824,000	65.6
1,000 MW N 2.5% S 30 yr	46,356,000	46.4

[a] Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling mid-1974.

Only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table 32. Comparison of Investment Requirements for SO_2 Removal Processes At 90% and 80% SO_2 Removal

Process	Projected total capital investment requirements, $ 500 MW new 3.5% S coal-fired units		Investment savings resulting from design for 80% SO_2 removal compared to 90%	
	90% SO_2 removal	80% SO_2 removal	$	%
Limestone slurry	25,163,000	24,267,000	896,000	3.6
Lime slurry	22,422,000	21,586,000	836,000	3.7
Magnesia slurry - regeneration	26,406,000	25,568,000	838,000	3.2
Sodium solution - SO_2 reduction	30,491,000	29,127,000	1,364,000	4.5

Table 33. Investment Requirements for SO_2 Removal Installations on Existing Power Units Requiring Additional Facilities for Removal of Particulates Comparison with Standard[a]

Process	Projected total capital investment requirements, $ 500 MW, existing 3.5% S coal-fired units		Difference in projected investment requirements	
	Requiring additional particulate removal facilities	Standard[a]	$	%
Limestone slurry	29,996,000	23,088,000	6,908,000	29.9
Lime slurry	26,090,000	26,027,000	63,000	0.2
Magnesia slurry - regeneration	32,213,000	26,026,000	6,187,000	23.8
Sodium solution - SO_2 reduction	37,957,000	31,208,000	6,749,000	21.6
Catalytic oxidation	43,816,000	37,907,000	5,909,000	15.6

[a] Standard case assumes that the existing electrostatic precipitator is adequate for existing units.

Table 34. Comparison of Investment Requirements for Limestone and Lime SO_2 Removal Processes Designed for On-site and Off-site Waste Solids Disposal

Process	On-site waste solids disposal	Off-site waste solids disposal	Difference in projected investment requirements	
			$	%
Limestone slurry	25,163,000	20,532,000	**4,631,000**	**18.4**
Lime slurry	22,422,000	18,323,000	4,099,000	18.3

regeneration process are the particulate removal and SO_2 absorption areas and the sulfuric acid processing area. For the sodium solution - SO_2 reduction process, the predominant cost areas are the particulate removal, SO_2 absorption, the SO_2 regeneration, and reduction areas. In the catalytic oxidation process, the particulate removal, SO_2 conversion, and sulfuric acid processing sections are the predominant cost areas.

In making an overall comparison of processes based on total investment, it should be noted that only the net difference in investment costs is seen. The difference in investment requirements between processes or between new and existing units can best be analyzed by looking at specific areas as shown in the base case and existing case summarized area equipment and installation breakdowns (tables 35-44). As an illustration using tables 35 and 36 for the limestone slurry process, a comparison of the overall investment indicates that costs for an existing power unit are less than for a new unit ($23,088,000 vs. $25,163,000). Comparison of the area costs, however, show similar areas to generally be more expensive for existing units than for new units. For example, direct investment costs for the

Table 35. Limestone Slurry Process
Total Capital Investment Requirements
Base Case[a] Summary—Process Equipment and Installation Analysis
(Thousands of Dollars)

Direct Costs	Raw materials handling	Feed preparation	Particulate scrubbing	SO_2 scrubbing	Reheat	Fans	Solids disposal	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Equipment													
Material	103	379	1,126	2,254	410	285	60		107		4,724	29.4	18.8
Labor	29	57	114	335	80	34	3		25		677	4.2	2.7
Piping and insulation													
Material	1	14	102	341	11		86	6			561	3.5	2.2
Labor	1	28	95	313	20		78	11			546	3.4	2.2
Ductwork, chutes, and supports													
Material	15	6	733	377		146					1,277	7.9	5.1
Labor	8	6	582	418		53					1,067	6.6	4.2
Concrete foundations													
Material	14	7	12	24		4	1				62	0.4	0.3
Labor	81	38	48	81		21	5				274	1.7	1.1
Excavation, site preparation, railroads, roads, and pond							3,028		339		3,367	21.0	13.4
Structural													
Material	11		84	85							180	1.1	0.7
Labor	10		38	41			2				91	0.6	0.4
Electrical													
Material	39	58	61	101	1	133	50	10			453	2.8	1.8
Labor	83	92	73	112	1	155	184	10			710	4.4	2.8
Instruments													
Material	8	49	77	162	21	15	11	16			359	2.2	1.4
Labor	4	25	38	81	11	7	5	8			179	1.1	0.7
Paint and miscellaneous													
Material	1	1	3	3			2	3			13	0.1	0.1
Labor	5	6	15	15	1	1	13	3			59	0.4	0.2
Buildings													
Material		65							113		178	1.1	0.7
Labor		67							40		107	0.7	0.4
Land	6	1	2	2			395		14		420	2.6	1.7
Construction facilities										765	765	4.8	3.0
Subtotal direct investment	419	899	3,203	4,745	556	854	3,923	67	638	765	16,069	100.0	63.9
Indirect Costs													
Engineering design and supervision	38	81	288	427	50	77	353	6	57	69	1,446	9.0	5.7
Construction field expense	46	99	352	522	61	94	432	8	70	84	1,768	11.0	7.0
Contractor fees	21	45	160	237	28	43	196	3	32	38	803	5.0	3.2
Contingency	42	90	320	474	56	85	392	7	64	77	1,607	10.0	6.4
Subtotal fixed investment	566	1,214	4,323	6,405	751	1,153	5,296	91	861	1,033	21,693	135.0	86.2
Allowance for startup and modifications	45	97	346	513	60	92	424	7	69	82	1,735	10.8	6.9
Interest during construction	45	97	346	513	60	92	424	7	69	82	1,735	10.8	6.9
Total capital investment	656	1,408	5,015	7,431	871	1,337	6,144	105	999	1,197	25,163	156.6	
Percent of total capital investment	2.6	5.6	19.9	29.5	3.5	5.3	24.4	0.4	4.0	4.8			100.0

[a] Basis

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal

Stack gas reheat to 175° F by indirect steam reheat

Disposal pond located 1 mile from power plant

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974

Minimum in process storage, only pumps are spared

Investment requirements for disposal of fly ash excluded

Construction labor shortages with accompanying overtime pay incentive not considered

Table 36. Limestone Slurry Process
Total Capital Investment Requirements
Existing Case[a] Summary—Process Equipment and Installation Analysis
(Thousands of Dollars)

	Raw materials handling	Feed preparation	SO_2 scrubbing	Reheat	Fans	Solids disposal	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Direct Costs												
Equipment												
Material	105	390	2,510	186	450	67	31	108		3,847	27.2	16.7
Labor	37	72	426	23	84	4	57	32		735	5.2	3.2
Piping and insulation												
Material	1	14	353	9		87	12			476	3.4	2.1
Labor	1	36	403	27		99	19			585	4.1	2.5
Ductwork, chutes, and supports												
Material	15	6	363		388					772	5.5	3.3
Labor	10	8	387		386					791	5.6	3.4
Concrete foundations												
Material	14	7	24		7	1	1			54	0.4	0.2
Labor	103	48	103	1	39	6	7			307	2.2	1.3
Excavation, site preparation, railroads, roads, and pond		–				2,734	46	422		3,202	22.7	13.9
Structural												
Material	11	–	86							97	0.7	0.4
Labor	13		52		–	3				68	0.5	0.3
Electrical												
Material	40	59	102	8	135	51	52	–		447	3.2	1.9
Labor	105	117	142	18	196	233	67		–	878	6.2	3.8
Instruments												
Material	8	50	165	35	15	11	20	–		304	2.1	1.3
Labor	5	32	103	16	9	6	12			183	1.3	0.8
Paint and miscellaneous												
Material	1	1	3			2	4			11	0.1	0.1
Labor	7	8	19		1	16	7			58	0.4	0.2
Buildings												
Material	–	66	–				–	114		180	1.3	0.8
Labor		85						50		135	0.9	0.6
Land	6	1	2		–	291	–	14		314	2.2	1.4
Construction facilities	–	–							672	672	4.8	2.9
Subtotal direct investment	482	1,000	5,243	323	1,710	3,611	335	740	672	14,116	100.0	61.1
Indirect Costs												
Engineering design and supervision	49	100	524	32	171	361	34	74	67	1,412	10.0	6.1
Construction field expense	63	130	682	42	222	469	44	96	87	1,835	13.0	8.0
Contractor fees	34	70	367	22	120	253	23	52	47	988	7.0	4.3
Contingency	53	110	577	36	188	397	37	81	74	1,553	11.0	6.7
Subtotal fixed investment	681	1,410	7,393	455	2,411	5,091	473	1,043	947	19,904	141.0	86.2
Allowance for startup and modifications	54	113	592	36	193	407	38	83	76	1,592	11.3	6.9
Interest during construction	54	113	592	36	193	407	38	83	76	1,592	11.3	6.9
Total capital investment	789	1,636	8,577	527	2,797	5,905	549	1,209	1,099	23,088	163.6	
Percent of total capital investment	3.4	7.1	37.1	2.3	12.1	25.6	2.4	5.2	4.8			100.0

[a] Basis:

500-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal; on-site solids disposal.
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table 37. Lime Slurry Process
Total Capital Investment Requirements
Base Case[a] Summary – Process Equipment and Installation Analysis
(Thousands of Dollars)

	Raw materials handling	Feed preparation	Particulate-SO_2 scrubbing	SO_2 scrubbing	Reheat	Fans	Solids disposal	Utilities	Services	Construction facilities	Total	Percent of direct investment	Percent of total capital investment
Direct Costs													
Equipment													
Material	350	145	1,016	1,076	410	285	11	–	82	–	3,375	23.6	15.0
Labor	50	14	380	380	80	34	2	–	25	–	965	6.7	4.3
Piping and insulation													
Material	–	10	363	363	7	–	80	6	–	–	829	5.8	3.7
Labor	–	10	338	341	12	–	92	11	–	–	804	5.6	3.6
Ductwork, chutes, and supports													
Material	9	2	785	175	–	153	–	–	–	–	1,124	7.8	5.0
Labor	5	1	644	196	–	54	–	–	–	–	900	6.3	4.0
Concrete foundations													
Material	10	3	12	13	–	4	–	–	–	–	42	0.3	0.2
Labor	46	12	47	47	–	21	1	–	–	–	174	1.2	0.8
Excavation site preparation railroads, roads, and pond	–	–	–	–	–	–	2,686	–	278	–	2,964	20.7	13.2
Structural													
Material	30	–	84	84	–	–	–	–	–	–	198	1.4	0.9
Labor	45	–	39	39	–	–	2	–	–	–	125	0.9	0.6
Electrical													
Material	96	41	48	89	1	88	60	10	–	–	433	3.0	1.9
Labor	109	47	55	101	1	100	68	10	–	–	491	3.4	2.2
Instruments													
Material	24	66	119	148	21	18	7	16	–	–	419	2.9	1.9
Labor	12	33	60	74	10	9	3	8	–	–	209	1.5	0.9
Paint and miscellaneous													
Material	1	–	3	3	–	–	1	3	–	–	11	0.1	0.1
Labor	7	3	23	23	–	1	5	3	–	–	65	0.4	0.3
Buildings													
Material	–	–	–	–	–	–	–	–	113	–	113	0.8	0.5
Labor	–	–	–	–	–	–	–	–	40	–	40	0.3	0.2
Land	1	–	1	1	–	–	338	–	14	–	355	2.5	1.6
Construction facilities	–	–	–	–	–	–	–	–	–	682	682	4.8	3.0
Subtotal direct investment	795	387	4,017	3,153	542	767	3,356	67	552	682	14,318	100.0	63.9
Indirect Costs													
Engineering design and supervision	72	35	361	284	49	69	302	6	50	61	1,289	9.0	5.7
Construction field expense	87	43	442	347	60	84	369	7	61	75	1,575	11.0	7.0
Contractor fees	40	19	201	158	27	38	168	3	28	34	716	5.0	3.2
Contingency	79	39	402	315	54	77	336	7	55	68	1,432	10.0	6.4
Subtotal fixed investment	1,073	523	5,423	4,257	732	1,035	4,531	90	746	920	19,330	135.0	86.2
Allowance for startup and modifications	86	42	434	340	58	83	362	7	60	74	1,546	10.8	6.9
Interest during construction	86	42	434	340	58	83	362	7	60	74	1,546	10.8	6.9
Total capital investment	1,245	607	6,291	4,937	848	1,201	5,255	104	866	1,068	22,422	156.6	
Percent of total capital investment	5.5	2.7	28.1	22.0	3.8	5.4	23.4	0.5	3.8	4.8			100.0

[a] Basis:

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal; on-site solids disposal.
Stack gas reheat to 175°F by indirect steam reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table 38. Lime Slurry Process
Total Capital Investment Requirements
Existing Case[a] Summary—Process Equipment and Installation Analysis
(Thousands of Dollars)

	Raw materials handling	Feed preparation	First stage SO_2 scrubbing	Second stage SO_2 scrubbing	Reheat	Fans	Calcium solids disposal	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Direct Costs													
Equipment													
Material	355	160	1,029	1,090	173	455	11	31	83		3,387	21.3	13.0
Labor	64	18	481	481	21	88	3	57	32		1,245	7.8	4.8
Piping and insulation													
Material		10	368	368	8		81	12			847	5.3	3.2
Labor		13	428	432	25		116	19			1,033	6.5	4.0
Ductwork, chutes, and supports													
Material	9	2	951	347		127					1,436	9.0	5.5
Labor	6	1	753	377		181					1,318	8.3	5.1
Concrete foundations													
Material	10	3	12	13		7		1			46	0.3	0.2
Labor	58	15	60	60	1	39	1	7			241	1.5	0.9
Excavation, site preparation, railroads, roads, and pond							2,420	46	356		2,822	17.7	10.8
Structural													
Material	31		85	85							201	1.3	0.8
Labor	57		49	49			3				158	1.0	0.6
Electrical													
Material	98	42	49	90	8	89	61	2			489	3.1	1.9
Labor	138	59	70	128	18	127	86	67			693	4.3	2.7
Instruments													
Material	24	67	121	150	35	18	7	20			442	2.8	1.7
Labor	15	42	76	94	16	11	4	12			270	1.7	1.0
Paint and miscellaneous													
Material	1		3	3			1	4			12	0.1	0.1
Labor	9	4	29	29		1	6	7			85	0.5	0.3
Buildings													
Material									114		114	0.7	0.4
Labor									50		50	0.3	0.2
Land	1		1	1			249		14		266	1.7	1.0
Construction facilities										758	758	4.8	2.9
Subtotal direct investment	876	436	4,565	3,797	305	1,143	3,049	335	649	758	15,913	100.0	61.1
Indirect Costs													
Engineering design and supervision	88	44	456	380	30	114	305	33	65	76	1,591	10.0	6.1
Construction field expense	114	57	593	494	40	149	396	44	84	98	2,069	13.0	8.0
Contractor fees	61	31	320	266	21	80	213	24	45	53	1,114	7.0	4.3
Contingency	96	48	502	418	34	126	335	37	71	83	1,750	11.0	6.7
Subtotal fixed investment	1,235	616	6,436	5,355	430	1,612	4,298	473	914	1,068	22,437	141.0	86.2
Allowance for startup and modifications	99	49	515	428	34	129	344	38	73	86	1,795	11.3	6.9
Interest during construction	99	49	515	428	34	129	344	38	73	86	1,795	11.3	6.9
Total capital investment	1,433	714	7,466	6,211	498	1,870	4,986	549	1,060	1,240	26,027	163.6	
Percent of total capital investment	5.5	2.7	28.7	23.9	1.9	7.2	19.1	2.1	4.1	4.8			100.0

[a] Basis
500-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal
Stack gas reheat to 175°F by direct oil-fired reheat
Disposal pond located 1 mile from power plant
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974
Minimum in process storage, only pumps are spared
Remaining life of power unit, 25 yr
Investment requirements for removal and disposal of fly ash excluded
Construction labor shortages with accompanying overtime pay incentive not considered

Table 39. Magnesia Slurry - Regeneration Process
Total Capital Investment Requirements
Base Case[a] Summary – Process Equipment and Installation Analysis
(Thousands of Dollars)

	Raw materials handling	Feed preparation	Particulate scrubbing	SO_2 scrubbing	Reheat	Fans	Slurry processing	Cake drying	$MgSO_3$ calcination	Sulfuric acid production	Acid storage & shipping	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Direct Costs																	
Equipment																	
Material	92	102	1,071	976	373	235	297	592	680	785	128	80	98		5,509	33.7	20.9
Labor	15	6	375	361	78	30	68	177	209	262	3	5	29		1,618	9.9	6.1
Piping and insulation																	
Material		15	206	200	11		60	1	3	230	12	8			746	4.5	2.8
Labor	1	13	188	186	20		58	1	6	234	30	24			761	4.6	2.9
Ductwork, chutes, and supports																	
Material		5	787	177		153	2	28	14	378					1,544	9.5	5.8
Labor		2	644	196		54	1	26	6	461					1,390	8.5	5.3
Concrete foundations																	
Material	1	1	15	11		4	3	6	6	38	7	3			95	0.6	0.4
Labor	6	6	57	41		19	12	29	27	175	35	28			435	2.7	1.6
Excavation, site preparation railroads, and roads											14	6	399		419	2.6	1.6
Structural																	
Material	4		84	84			3	7	6	78	2	2			270	1.7	1.0
Labor	2		41	38			1	4	9	35	14	14			158	1.0	0.6
Electrical																	
Material	25	25	91	51	1	101	47	32	31	91	6	26			527	3.2	2.0
Labor	28	37	175	57	1	115	75	36	44	144	15	30			757	4.6	2.9
Instruments																	
Material	10	15	136	124	16	20	53	17	38	138	9	16			592	3.6	2.2
Labor	5	7	68	62	8	10	26	8	19	71	3	8			295	1.8	1.1
Paint and miscellaneous																	
Material		1	3	3				1	1	9		8			26	0.2	0.1
Labor	3	3	24	24	1		3	6	8	65		11			148	0.9	0.6
Buildings																	
Material													180		180	1.1	0.7
Labor													63		63	0.4	0.2
Land			1	1			2	1	1	3			14		23	0.1	0.1
Construction facilities														778	778	4.8	2.9
Subtotal direct investment	192	238	3,966	2,592	509	741	711	972	1,108	3,197	278	269	783	778	16,334	100.0	61.8
Indirect Costs																	
Engineering design and supervision	21	26	436	285	56	81	78	107	122	352	31	30	86	86	1,797	11.0	6.8
Construction field expense	21	26	436	285	56	81	78	107	122	352	31	30	86	86	1,797	11.0	6.8
Contractor fees	10	12	198	130	25	37	36	49	55	160	14	13	39	39	817	5.0	3.1
Contingency	19	24	396	259	51	74	71	97	111	320	28	27	78	78	1,633	10.0	6.2
Subtotal fixed investment	263	326	5,432	3,551	697	1,014	974	1,332	1,518	4,381	382	369	1,072	1,067	22,378	137.0	84.7
Allowance for startup and modifications	26	33	543	355	70	102	97	133	152	438	38	37	107	107	2,238	13.7	8.5
Interest during construction	21	26	434	284	56	81	78	107	121	350	31	30	86	85	1,790	11.0	6.8
Total capital investment	310	385	6,409	4,190	823	1,197	1,149	1,572	1,791	5,169	451	436	1,265	1,259	26,406	161.7	
Percent of total capital investment	1.2	1.5	24.3	15.9	3.1	4.5	4.3	5.9	6.8	19.6	1.7	1.6	4.8	4.8			100.0

[a] Basis:

500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 15.8 tons/hr 100% H_2SO_4.
Stack gas reheat to 175° F by indirect steam reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for 1st stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table 40. Magnesia Slurry - Regeneration Process
Total Capital Investment Requirements
Existing Case[a] Summary—Process Equipment and Installation Analysis
(Thousands of Dollars)

Direct Costs	Raw materials handling	Feed preparation	SO_2 scrubbing	Reheat	Fans	Slurry processing	Cake drying	$MgSO_3$ calcination	Sulfuric acid production	Acid storage & shipping	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Equipment																
Material	93	113	990	173	433	306	606	694	796	149	130	99		4,582	29.7	17.6
Labor	19	8	457	21	56	87	225	265	332	4	9	36		1,519	9.9	5.9
Piping and insulation																
Material		15	203	8		61	1	3	233	12	10			546	3.6	2.1
Labor	1	16	236	25		74	1	8	297	38	33			729	4.7	2.8
Ductwork, chutes, and supports																
Material		5	1,133		128	2	29	14	383					1,694	11.0	6.5
Labor		3	891		181	1	33	8	584					1,701	11.0	6.5
Concrete foundations																
Material	1	1	11		5	3	6	6	39	7	4			83	0.5	0.3
Labor	8	8	52	1	27	15	37	34	222	44	50			498	3.2	1.9
Excavation, site preparation, railroads, and roads										17	10	456		483	3.2	1.9
Structural																
Material	4		85			3	7	6	79	2	3			189	1.2	0.7
Labor	3		48			1	5	11	44	18	25			155	1.0	0.6
Electrical																
Material	25	25	52	8	103	48	32	31	92	6	57			479	3.1	1.9
Labor	36	47	72	18	146	95	46	56	183	19	70			788	5.1	3.0
Instruments																
Material	10	15	126	35	20	54	17	39	140	9	16			481	3.1	1.9
Labor	6	9	79	16	13	33	10	24	90	4	10			294	1.9	1.1
Paint and miscellaneous																
Material		1	3				1	1	9		10			25	0.2	0.1
Labor	4	4	30			4	8	10	82		17			159	1.0	0.6
Buildings																
Material												182		182	1.2	0.7
Labor												80		80	0.5	0.3
Land			1			2	1	1	3			14		22	0.1	0.1
Construction facilities													734	734	4.8	2.8
Subtotal direct investment	210	270	4,469	305	1,112	789	1,065	1,211	3,608	329	454	867	734	15,423	100.0	59.3
Indirect Costs																
Engineering design and supervision	25	32	536	37	133	96	128	145	433	40	54	104	88	1,851	12.0	7.1
Construction field expense	27	35	581	40	145	103	138	157	469	43	59	113	95	2,005	13.0	7.7
Contractor fees	15	19	313	21	78	55	74	85	253	23	32	61	51	1,080	7.0	4.1
Contingency	23	30	492	34	122	87	117	133	397	36	50	95	81	1,697	11.0	6.5
Subtotal fixed investment	300	386	6,391	437	1,590	1,130	1,522	1,731	5,160	471	649	1,240	1,049	22,056	143.0	84.7
Allowance for startup and modifications	30	39	639	44	159	113	152	173	516	47	65	124	105	2,206	14.3	8.5
Interest during construction	24	31	511	35	127	90	122	138	413	38	52	99	84	1,764	11.4	6.8
Total capital investment	354	456	7,541	516	1,876	1,333	1,796	2,042	6,089	556	766	1,463	1,238	26,026	168.7	
Percent of total capital investment	1.4	1.8	29.0	2.0	7.2	5.1	6.9	7.8	23.4	2.1	2.9	5.6	4.8			100.0

[a] Basis:

500-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 16.1 tons/hr 100% H_2SO_4

Stack gas reheat to 175 °F by direct oil-fired reheat

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974

Minimum in process storage; only pumps are spared

Remaining life of power unit, 25 yr

Investment requirements for removal and disposal of fly ash excluded

Construction labor shortages with accompanying overtime pay incentive not considered

Table 41. Sodium Solution - SO_2 Reduction Process
Total Capital Investment Requirements
Base Case[a] Summary – Process Equipment and Installation Analysis
(Thousands of Dollars)

	Raw materials handling & preparation	Particulate scrubbing	SO_2 scrubbing	Reheat	Fans	Purge treatment	SO_2 regeneration	SO_2 reduction	Sulfur storage & shipping	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Direct Costs															
Equipment															
Material	90	1,071	2,183	410	285	749	1,628	1,870	103		98		8,487	44.9	27.8
Labor	19	375	709	80	34	133	145	846	2		29		2,372	12.6	7.8
Piping and insulation															
Material	2	208	146	11		63	104	2	6	58			600	3.2	2.0
Labor	5	194	135	20		61	119	5	11	45			595	3.2	2.0
Ductwork, chutes, and supports															
Material		726	238		157	54	6	55					1,236	6.6	4.0
Labor		574	264		59	73	10	90					1,070	5.7	3.5
Concrete foundations															
Material	1	15	11		4	15	14		4				64	0.3	0.2
Labor	6	57	41		21	64	67		16				272	1.4	0.9
Excavation, site preparation, railroads, and roads									13		278		291	1.5	1.0
Structural															
Material	5	84	84			27	92		2				294	1.6	0.9
Labor	3	41	38			13	42		14				151	0.8	0.5
Electrical															
Material	25	88	67	1	157	65	106	30	16	12			567	3.0	1.8
Labor	47	167	160	1	149	91	160	21	23	17			836	4.4	2.7
Instruments															
Material	13	145	110	10	15	37	131		9	17			487	2.6	1.6
Labor	7	73	55	5	7	18	65		4	8			242	1.3	0.8
Paint and miscellaneous															
Material		3	3			1	3			14			24	0.1	0.1
Labor	2	24	24	1	1	8	23		1	24			108	0.6	0.4
Buildings															
Material											180		180	1.0	0.6
Labor											63		63	0.3	0.2
Land		1	1			1	2	2	3		14		24	0.1	0.1
Construction facilities												898	898	4.8	2.9
Subtotal direct investment	225	3,846	4,269	539	889	1,473	2,717	2,921	227	195	662	898	18,861	100.0	61.8
Indirect Costs															
Engineering design and supervision	25	423	470	59	98	162	299	321	25	21	73	99	2,075	11.0	6.8
Construction field expense	25	423	470	59	98	162	299	321	25	21	73	99	2,075	11.0	6.8
Contractor fees	11	192	214	27	44	74	136	146	11	10	33	45	943	5.0	3.1
Contingency	22	385	427	54	89	147	272	292	23	19	66	90	1,886	10.0	6.2
Subtotal fixed investment	308	5,269	5,850	738	1,218	2,018	3,723	4,001	311	266	907	1,231	25,840	137.0	84.7
Allowance for startup and modifications	31	527	584	74	122	202	372	400	31	27	91	123	2,584	13.7	8.5
Interest during construction	25	422	468	59	97	161	298	320	25	21	73	98	2,067	11.0	6.8
Total capital investment	364	6,218	6,902	871	1,437	2,381	4,393	4,721	367	314	1,071	1,452	30,491	161.7	
Percent of total capital investment	1.2	20.4	22.6	2.9	4.7	7.8	14.4	15.5	1.2	1.0	3.5	4.8			100.0

[a] Basis:

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 4.7 tons/hr S produced.
Stack gas reheat to 175°F by indirect steam reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal, closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table 42. Sodium Solution - SO_2 Reduction Process
Total Capital Investment Requirements
Existing Case[a] Summary—Process Equipment and Installation Analysis
(Thousands of Dollars)

	Raw materials handling & preparation	SO_2 scrubbing	Reheat	Fans	Purge treatment	SO_2 regeneration	SO_2 reduction	Sulfur storage & shipping	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Direct Costs														
Equipment														
Material	92	2,218	173	462	730	1,928	1,892	120	98	99	–	7,812	42.3	25.0
Labor	24	902	21	62	198	293	1,070	2	184	37	–	2,793	15.2	8.9
Piping and insulation														
Material	2	149	8	–	59	106	2	6	59	–	–	391	2.1	1.3
Labor	6	171	25	–	65	151	7	14	50	–	–	489	2.6	1.6
Ductwork, chutes, and supports														
Material	–	1,046	–	127	55	6	55	–	–	–	–	1,289	7.0	4.1
Labor	–	766	–	181	92	13	115	–	–	–	–	1,167	6.3	3.7
Concrete foundations														
Material	1	11	–	5	15	14	–	4	3	–	–	53	0.3	0.2
Labor	8	52	1	29	81	85	–	20	21	–	–	297	1.6	1.0
Excavation, site preparation, railroads, and roads	–	–	–	–	–			17	107	354	–	478	2.6	1.5
Structural														
Material	5	85	–	–	28	94	–	2	–	–	–	214	1.2	0.7
Labor	3	48	–	–	16	53	–	18	–	–	–	138	0.7	0.4
Electrical														
Material	25	69	8	159	66	108	30	16	59	–	–	540	2.9	1.7
Labor	60	204	18	188	115	203	27	29	79	–	–	923	5.0	3.0
Instruments														
Material	14	111	35	15	38	133	–	9	23	–	–	378	2.0	1.2
Labor	9	70	16	9	23	83	–	6	14	–	–	230	1.2	0.7
Paint and miscellaneous														
Material	–	3	–	–	1	3	–	–	16	–	–	23	0.1	0.1
Labor	2	31	–	1	10	29	–	1	39	–	–	113	0.6	0.4
Buildings														
Material	–	–	–	–	–	–	–	–	–	182	–	182	1.0	0.6
Labor	–	–	–	–	–	–	–	–	–	80	–	80	0.4	0.3
Land	–	2	–	–	1	2	2	3	–	14	–	24	0.1	0.1
Construction facilities	–	–	–	–	–	–	–	–	–	–	881	881	4.8	2.8
Subtotal direct investment	251	5,938	305	1,238	1,593	3,304	3,200	267	752	766	881	18,495	100.0	59.3
Indirect Costs														
Engineering design and supervision	30	712	37	149	191	396	384	32	90	92	106	2,219	12.0	7.1
Construction field expense	33	772	40	161	207	429	416	35	98	99	114	2,404	13.0	7.7
Contractor fees	17	416	21	87	111	231	224	19	53	54	62	1,295	7.0	4.1
Contingency	28	653	34	136	175	363	352	29	83	84	97	2,034	11.0	6.5
Subtotal fixed investment	359	8,491	437	1,771	2,277	4,723	4,576	382	1,076	1,095	1,260	26,447	143.0	84.7
Allowance for startup and modifications	36	849	44	177	228	472	458	38	108	109	126	2,645	14.3	8.5
Interest during construction	29	679	35	142	182	378	366	30	86	88	101	2,116	11.4	6.8
Total capital investment	424	10,019	516	2,090	2,687	5,573	5,400	450	1,270	1,292	1,487	31,208	168.7	
Percent of total capital investment	1.4	32.1	1.6	6.7	8.6	17.9	17.3	1.4	4.1	4.1	4.8			100.0

[a] Basis:
500-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 4.8 tons/hr S produced.
Stack gas reheat to 175°F by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table 43. Catalytic Oxidation Process
Total Capital Investment Requirements
Base Case[a] Summary–Process Equipment and Installation Analysis
(Thousands of Dollars)

	Startup bypass ducts	Particulate removal	SO_2 conversion	Heat recovery	Fans	H_2SO_4 absorption cooling	Acid storage & shipping	Utilities	Services	Construction facilities	Total	Percent of direct investment	Percent of total capital investment
Direct Costs													
Equipment													
Material		4,469	671	(31)	316	5,659	68		36		11,188	44.1	26.3
Labor		3,126	556	(25)	43	760	101		9		4,570	18.0	10.7
Piping and insulation													
Material				121		275	13	2			411	1.6	1.0
Labor			1	166		259	31	5			462	1.8	1.1
Ductwork, chutes, and supports													
Material	350	585	465	425	302	684					2,811	11.1	6.6
Labor	97	319	197	384	229	513					1,739	6.9	4.1
Concrete foundations													
Material			4	4	5	27	11				51	0.2	0.1
Labor			17	15	24	124	48				228	0.9	0.5
Excavation, site preparation, railroads, and roads							19		278		297	1.2	0.7
Structural													
Material			56			23	2				81	0.3	0.2
Labor			43			5	14				62	0.2	0.1
Electrical													
Material	15	64	23	78	203	77	30	10			500	2.0	1.2
Labor	20	129	42	193	265	149	43	10			851	3.4	2.0
Instruments													
Material	6	28	42	85	16	233	18	16			444	1.7	1.0
Labor	3	14	21	43	8	117	9	8			223	0.9	0.5
Paint and miscellaneous													
Material			1	2		1		3			7	0.0	0.0
Labor			5	14	1	9		3			32	0.1	0.1
Buildings													
Material									132		132	0.5	0.3
Labor									50		50	0.2	0.1
Land		2	1	1		2	2		13		21	0.1	0.0
Construction facilities										1,208	1,208	4.8	2.8
Subtotal direct investment	491	8,736	2,145	1,475	1,412	8,917	409	57	518	1,208	25,368	100.0	59.4
Indirect Costs													
Engineering design and supervision	54	961	236	162	155	981	45	6	57	133	2,790	11.0	6.5
Construction field expense	54	961	236	162	155	981	45	6	57	133	2,790	11.0	6.5
Contractor fees	25	437	107	74	71	445	20	3	26	60	1,268	5.0	3.0
Contingency	49	874	214	147	141	892	41	6	52	121	2,537	10.0	5.9
Subtotal fixed investment	673	11,969	2,938	2,020	1,934	12,216	560	78	710	1,655	34,753	137.0	81.3
Allowance for startup and modifications	67	1,197	294	202	193	1,222	56	8	71	165	3,475	13.7	8.2
Interest during construction	54	957	235	162	155	977	45	6	57	132	2,780	11.0	6.5
Total capital investment excluding catalyst	794	14,123	3,467	2,384	2,282	14,415	661	92	838	1,952	41,008	161.7	96.0
Catalyst			1,728								1,728	6.8	4.0
Total capital investment	794	14,123	5,195	2,384	2,282	14,415	661	92	838	1,952	42,736	168.5	
Percent of total capital investment	1.9	33.0	12.2	5.6	5.3	33.7	1.5	0.2	2.0	4.6			100.0

[a] Basis:

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 15.7 tons/hr 100% H_2SO_4.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table 44. Catalytic Oxidation Process
Total Capital Investment Requirements
Existing Case[a] Summary—Process Equipment and Installation Analysis
(Thousands of Dollars)

	Startup bypass ducts	Particulate removal	SO_2 conversion	Reheat	Fans	H_2SO_4 absorption & cooling	Acid storage & shipping	Utilities	Services	Construction facilities 5%	Total	Percent of direct investment	Percent of total capital investment
Direct Costs													
Equipment													
Material	–	1,471	683	1,894	688	4,247	69	65	36	–	9,153	42.7	24.1
Labor	–	1,553	708	160	98	857	128	122	11	–	3,637	17.0	9.6
Piping and insulation													
Material	–	–	–	244	–	176	13	13	–	–	446	2.1	1.2
Labor	–	–	1	293	–	214	39	15	–	–	562	2.6	1.5
Ductwork, chutes, and supports													
Material	179	483	136	–	305	308	–	–	–	–	1,411	6.6	3.7
Labor	74	475	164	–	413	273	–	–	–	–	1,399	6.5	3.7
Concrete foundations													
Material	–	–	4	23	9	24	11	2	–	–	73	0.3	0.2
Labor	–	–	22	26	53	141	61	14	–	–	317	1.5	0.8
Excavation, site preparation, railroads, and roads	–	–	–	–	–	–	22	79	356	–	457	2.1	1.2
Structural													
Material	–	–	57	–	–	24	3	–	–	–	84	0.4	0.2
Labor	–	–	54	–	–	6	18	–	–	–	78	0.4	0.2
Electrical													
Material	15	65	23	172	206	61	31	73	–	–	646	3.0	1.7
Labor	26	164	53	199	334	148	55	95	–	–	1,074	5.0	2.8
Instruments													
Material	6	29	43	133	16	214	18	22	–	–	481	2.2	1.3
Labor	4	18	27	97	10	134	11	13	–	–	314	1.5	0.8
Paint and miscellaneous													
Material	–	–	1	8	–	1	–	4	–	–	14	0.1	0.0
Labor	–	–	6	8	1	10	–	10	–	–	35	0.2	0.1
Buildings													
Material	–	–	–	–	–	–	–	–	133	–	133	0.6	0.4
Labor	–	–	–	–	–	–	–	–	63	–	63	0.3	0.2
Land	–	2	1	1	–	2	2	–	14	–	22	0.1	0.1
Construction facilities	–	–	–	–	–	–	–	–	–	1,020	1,020	4.8	2.7
Subtotal direct investment	304	4,260	1,983	3,258	2,133	6,840	481	527	613	1,020	21,419	100.0	56.5
Indirect Costs													
Engineering design and supervision	36	511	238	391	256	821	58	63	74	122	2,570	12.0	6.8
Construction field expense	39	554	258	424	277	889	62	68	80	133	2,784	13.0	7.3
Contractor fees	21	298	139	228	149	479	34	37	43	71	1,499	7.0	4.0
Contingency	33	469	218	358	235	753	53	58	67	112	2,356	11.0	6.2
Subtotal fixed investment	433	6,092	2,836	4,659	3,050	9,782	688	753	877	1,458	30,628	143.0	80.8
Allowance for startup and modification	43	609	284	466	305	978	69	75	88	146	3,063	14.3	8.1
Interest during construction	35	487	227	373	244	782	55	60	70	117	2,450	11.4	6.4
Total capital investment excluding catalyst	511	7,188	3,347	5,498	3,599	11,542	812	888	1,035	1,721	36,141	168.7	95.3
Catalyst	–	–	1,766	–	–	–	–	–	–	–	1,766	8.3	4.7
Total capital investment	511	7,188	5,113	5,498	3,599	11,542	812	888	1,035	1,721	37,907	177.0	–
Percent of total capital investment	1.4	19.0	13.5	14.5	9.5	30.5	2.1	2.3	2.7	4.5	–		100.0

[a] Basis:

500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 16.0 tons/hr 100% H_2SO_4.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Only pumps are spared.

Remaining life of power unit, 25 yr.

Investment requirements for removal and disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table 45. Investment Distribution for Major Cost Areas—Base Case Total Capital Investment[a]

Area	Limestone slurry process	Lime slurry process	Magnesia slurry - regeneration process	Sodium solution - SO_2 reduction process	Catalytic oxidation process
	Distribution of base case total capital investment, %				
Particulate removal	19.9	28.1	24.3	20.4	33.0
SO_2 conversion	—	—	—	—	12.2
SO_2 absorption	29.5	22.0	15.9	22.6	—
Waste disposal	24.4	23.4	—	—	—
Sulfuric acid processing	—	—	19.6	—	33.7
SO_2 regeneration	—	—	—	14.4	—
SO_2 reduction	—	—	—	15.5	—
Subtotal, %	73.8	73.5	59.8	72.9	78.9
Total capital investment, M $	25,163	22,422	26,406	30,491	42,736

[a]Major cost areas are defined as those which account for more than 10% of the total capital investment.

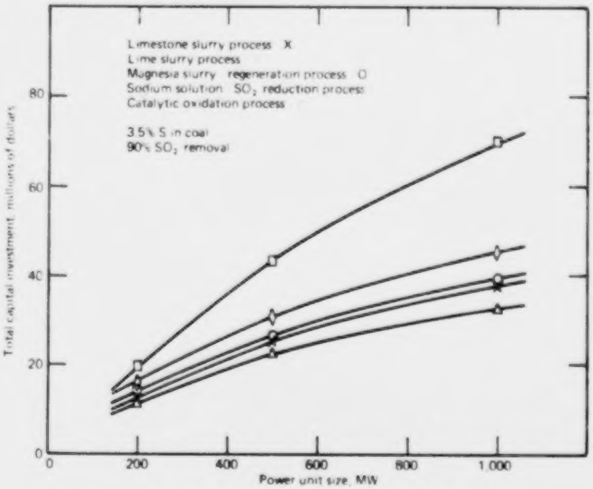


Figure 33. All processes. Effect of power unit size on total capital investment: new coal-fired units

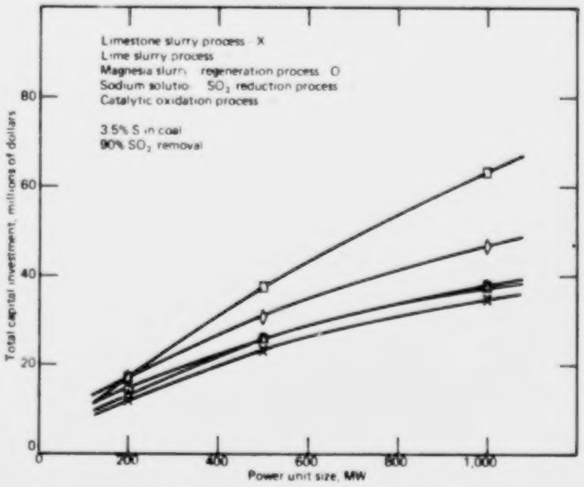


Figure 35. All processes. Effect of power unit size on total capital investment: existing coal-fired units

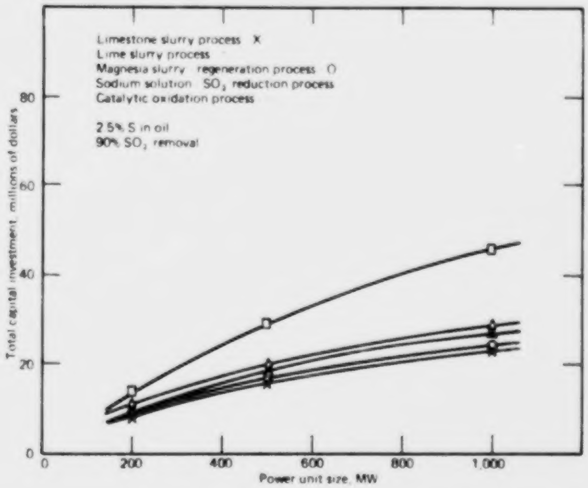


Figure 34. All processes. Effect of power unit size on total capital investment: new oil-fired units

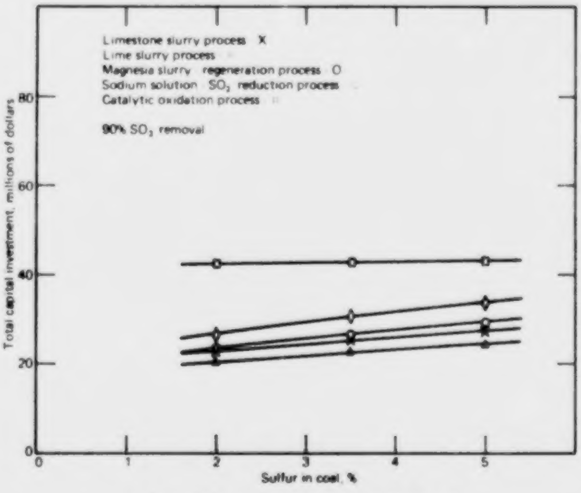


Figure 36. All processes. Effect of sulfur content of coal on total capital investment: new 500-MW coal-fired units

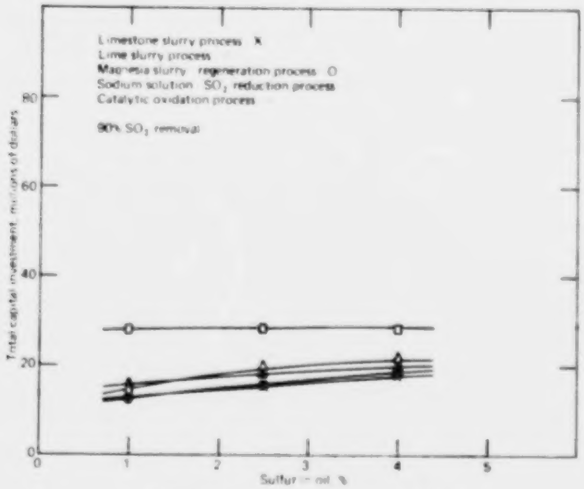


Figure 37. All processes. Effect of sulfur content of oil on total capital investment: new 500-MW oil-fired units

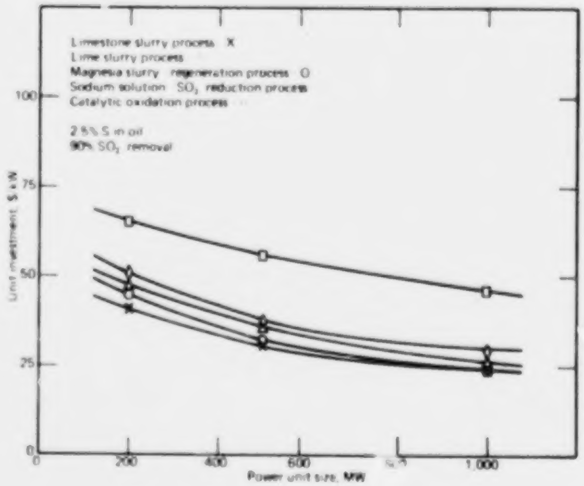


Figure 39. All processes. Effect of power unit size on unit investment cost, dollars per kilowatt: new oil-fired units

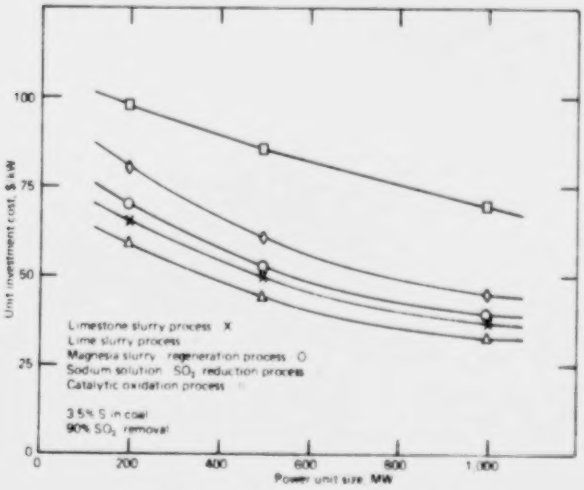


Figure 38. All processes. Effect of power unit size on unit investment cost, dollars per kilowatt: new coal-fired units

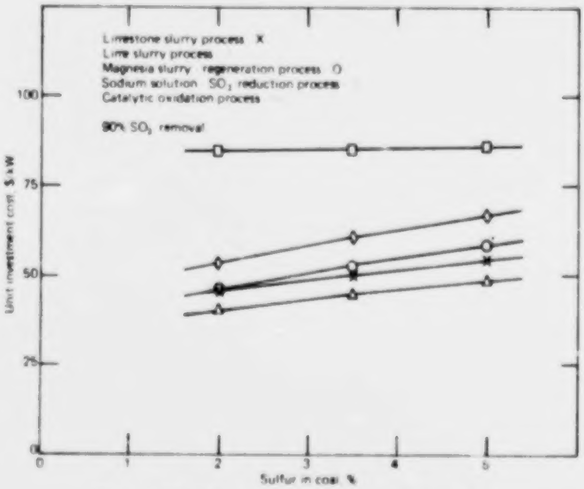


Figure 40. All processes. Effect of sulfur content of coal on unit investment cost, dollars per kilowatt: new 500-MW coal-fired units

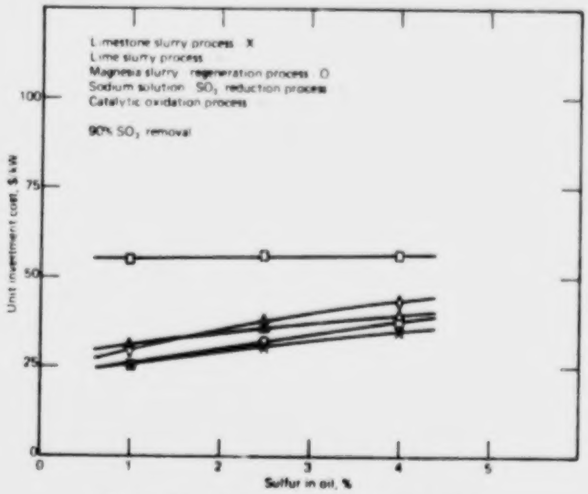


Figure 41. All processes. Effect of sulfur content of oil on unit investment cost, dollars per kilowatt: new 500-MW oil-fired units

SO_2 scrubbing area are projected as $4,745,000 for a new unit in comparison to $5,243,000 for an existing unit, and incremental fan costs for a new unit are projected as $854,000 in comparison to supplemental fan costs of $1,710,000 for an existing unit. Certain areas are less expensive for existing units, however. The omission of a particulate scrubber for existing units saves approximately $3,203,000 (since particulate emission regulations are assumed already met) and direct investment costs for an oil-fired reheat system on an existing unit ($323,000) are lower than corresponding costs for an indirect steam reheat system for a new unit ($556,000). The overall difference in costs between new and existing units for the various processes is mainly attributed to differences in ductwork, particulate removal requirements, the use of direct oil-fired reheat as opposed to indirect steam reheat, and the assumed 25% higher installation labor costs for existing units as compared to new units.

The required investment for existing power units utilizing the limestone and lime slurry processes varies with operating profile and remaining life of the power plant, due to corresponding variations in the quantities of waste solids to be disposed. In comparison, however, investment requirements for the recovery processes do not vary with plant age. Figure 42 shows the effect of power unit size and years remaining life on the projected total capital investment required for the limestone slurry process applied to existing power units. The relationship for the lime slurry process is similar.

Base case equipment lists indicating size/scale factors and the sources of the equipment cost data for each of the five processes are presented in tables 46 through 50.

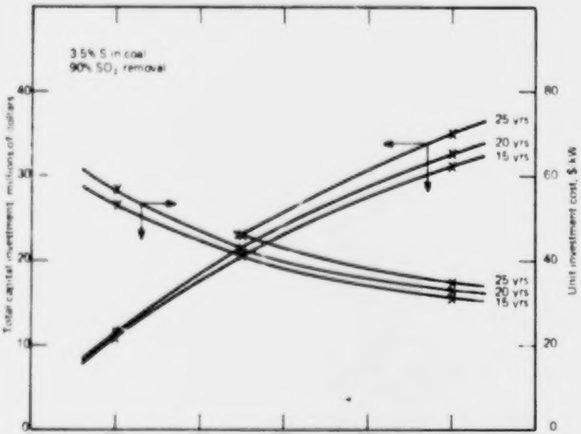


Figure 42. Limestone slurry process. Effect of years remaining life on total capital investment: existing coal-fired units

Annual Operating Cost

Projected annual operating costs under regulated economics for the five processes are presented using the three methods discussed earlier. Summary tables giving the projected annual operating cost for the base case and 16 variations for each process are given in Appendix B and tabular summaries of the projected annual operating cost and equivalent unit operating costs are given in tables 51 through 55. In order that direct comparisons can be made, credits for recovery products have not been included; these will be applied in determining lifetime operating costs in a later section.

Generally, the operating costs for the limestone slurry process are the lowest of the five processes and those for the sodium solution - SO_2 reduction process are the highest. However, some very important exceptions are emphasized in plots of the results. Figures 43 through 50 show the effects of power unit size, fuel type, and sulfur content of fuel on annual and unit operating costs. As the projections show, the ranking of operating costs for the five processes depends to a small degree on the size of the plant but to a larger degree on the sulfur content of fuel. For new 500-MW power units utilizing 1.0% sulfur oil, the projected annual operating costs for the catalytic oxidation process rank among the highest of the five processes (figure 50), however, for oil-fired units utilizing high-sulfur oil (>4.0%) the projected annual operating costs for the Cat-Ox process are the lowest. The slight decrease in annual operating cost for the Cat-Ox process with increasing sulfur content of fuel oil is the result of a greater amount of heat recovered for the high sulfur installations in conjunction with the higher unit cost for recovered heat assumed for oil-fired units.

Several special cases are shown in the total average annual operating cost summaries:

80% SO_2 removal

Particulate removal for existing unit

Off-site solids disposal

Additional information on the treatment of these cases is provided in tables 56 through 58.

Table 56 shows the effect of designing for 80% SO_2 removal instead of the assumed standard of 90% on annual operating costs for the limestone slurry process, lime slurry process, magnesia slurry - regeneration process and the sodium solution - SO_2 reduction process. Designing for 80% SO_2 removal instead of 90% would result in a savings of only 3.6% to 6.6% of the projected annual operating cost.

Results of an evaluation of the annual operating costs for existing units requiring additional facilities for removal of particulates but excluding costs for ash disposal are given in table 57. The standard case assumes that existing electrostatic precipitators are adequate for existing plants. Since the lime slurry process is designed with a two-stage

Table 46. Limestone Slurry Process Equipment List and Cost

Area 1 Material Handling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Unloading hopper No. 1	1	Capacity 94 ft^3; 8'-4" side, 2'-4" bottom, 3' deep, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	1,700	Catalytic Inc.	1973	2,000	2,000
2. Limestone feeder No. 1 (vibrating)	1	210 tons/hr, 42" wide x 5' long pan, 2½ hp vibrator included, carbon steel	0.58	Chem. Engr. 3-24-69 Guthrie	2,691	Richardson Engr. Services	1971	3,300	3,300
3. Conveyor (belt) No. 1	1	210 tons/hr, 250 ft/min, 24" belt, 10' long, 2½ hp motor included, carbon steel	0.81 0.65	Fund. of Cost Engr. 1964 Chem. Engr. 3-24-69 Guthrie	1,887	TVA work order D05C30	1964	2,900	2,900
4. Conveyor (belt) No. 2	1	210 tons/hr, 250 ft/min, 24" belt, 172' long, 20 hp motor included, carbon steel	0.81 0.65	Fund. of Cost Engr. 1964 Chem. Engr. 3-24-69 Guthrie	8,948	TVA work order D05P353	1962	13,700	13,700
5. Hoppers under pile	3	7'-4" top, 1'-4" bottom, 3' deep, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	1,300	Chem. Engr.-3-24-69, Guthrie	1969	1,700	5,100
6. Limestone feeder No. 2 (vibrating)	3	100 tons/hr, 18" wide x 3½' long pan, 1 hp vibrator included, carbon steel	0.58	Chem. Engr. 3-24-69 Guthrie	1,550	Richardson Engr. Services	1973	1,700	5,100
7. Conveyor (belt) No. 3	1	250 ft/min, 18" belt, 135' long, 3 hp motor included, carbon steel	0.65 0.81	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	11,250	Chem. Engr.-3-24-69, Guthrie	1969	14,800	14,800
8. Tunnel sump pump	2	5 gpm, 10' head, ¼ hp motor included, carbon steel, neoprene lining	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		560	Catalytic Inc.	1973	600	1,200
9. Elevator No. 1	1	100 tons/hr @ 85 lb/ft^3, 16" x 8" x 8½" bucket, 235 ft/min, 15 hp motor included, carbon steel	0.83	Chem. Engr. 3-24-69 Guthrie	8,765	TVA work order D05C30	1964	13,300	13,300
10. Bin	1	5,000 ft^3, 3/8" carbon steel plate, plus structural steel	0.68	Chem. Engr. 3-24-69 Guthrie	12,650	TVA work order D05C30	1964	19,200	19,200
11. Car shaker	1	Railroad trackside vibrator			4,866	TVA work order D05C30	1965	6,600	6,600
12. Dust collecting system No. 1	1	2,000 cfm inertial separator, XQ cyclone, 2 dust hoppers, fan, and drive	0.80	Chem. Engr. 3-24-69 Guthrie	2,392	Richardson Engr. Services	1973	2,600	2,600
13. Dust collecting system No. 2	1	6,000 cfm inertial separator, XQ cyclone, 2 dust hoppers, fan, and drive	0.80	Chem. Engr. 3-24-69 Guthrie	4,724	Richardson Engr. Services	1973	5,100	5,100
14. Bag filter system	1	14,000 cfm, automatic fabric dust collectors, bag support, shaker system, isolation damper, external shaker motor and drive, dust hopper, fan and motor for bag filter system (½ in feed preparation area)	0.68	Chem. Engr. 3-24-69 Guthrie	7,926	Richardson Engr. Services	1973	8,500	8,500
Subtotal									103,400

Table 46. Limestone Slurry Process (Cont.)

Area 2 Feed Preparation

Item	No	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Bin discharge feeder	2	12½ tons/hr, 10" wide x 2½ long pan, vibrator included, carbon steel	0.58	Chem. Engr. 3-24-69 Guthrie	500	Richardson Engr. Services	1973	600	1,200
2. Weigh feeder	2	12½ tons/hr, 18" belt, 14′ long, 1½ hp motor included, carbon steel	0.65	Chem. Engr. 3-24-69 Guthrie	7,216	Catalytic Inc.	1972	8,200	16,400
3. Gyratory crusher	2	12½ tons/hr, 0 x 1½ to ¾", 25 hp motor included	1.20	Chem. Engr. 3-24-69 Guthrie	10,455	Denver Equip. Co.	1973	11,300	22,600
4. Elevator No. 2	2	12½ tons/hr, 85 lb/ft^3, 235 ft/min, 24′ ctrs, 6" x 4" x 4¼" bucket, 1 hp motor included	0.65	Chem. Engr. 3-24-69 Guthrie	1,760	Chem. Engr. 3-24-69, Guthrie	1969	2,400	4,800
5. Wet ball mill	2	300 tons/day; 8′ dia x 12′ long, from ¾" to 200 mesh	0.65	Chem. Engr. 3-24-69 Guthrie	99,245	Denver Equip. Co.	1973	108,150	216,300
	2	450 hp motors for ball mill	1.07	Fund. of Cost Engr. 1964	13,100	Westinghouse	1973	14,200	28,400
6. Mills product tank	1	1,920 gal, 8′ diameter x 5′ high, vertical with open top, carbon steel	0.52	Fund. of Cost Engr. 1964	2,120	GATX	1971	2,500	2,500
Lining		Neoprene lining for mill product tank			1,400	GATX	1971	800	800
7. Agitator, mills product tank	1	1 hp, neoprene coated	0.50 0.26	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	1,026	Mixing Equip. Co., Inc.	1971	1,200	1,200
8. Pumps, mills product tank	2	96 gpm, 58′ head, centrifugal, with variable speed drive and 3 hp motor, carbon steel, neoprene lining	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,060	Denver Equip. Co.	1973	2,200	4,400
9. Slurry feed tank	1	46,080 gal, 6,160 ft^3, 17′-4" diameter x 27′ high, vertical with open top, (4) 1′-5" wide baffles, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	16,000	GATX	1971	19,200	19,200
Lining		¼" neoprene lining			14,000	GATX	1971	17,000	17,000
10. Agitator, slurry feed tank	1	10 hp, neoprene coated	0.50 0.46	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	4,717	Mixing Equip. Co., Inc.	1971	5,600	5,600
11. Pumps, slurry feed tank	2	96 gpm, 58′ head, centrifugal, with variable speed drive and 3 hp motor, carbon steel, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller size		2,060	Denver Equip. Co.	1973	2,200	4,400
12. Dust collecting system	1	8,000 cfm, inertial separator, XQ cyclone, 2 dust hoppers, fan and drive	0.80	Chem. Engr. 3-24-69 Guthrie	5,894	Richardson Engr. Services	1973	6,400	6,400
13. Hoist	1	5 ton electric	0.81	Popper, H.	17,570	Richardson Engr. Services	1973	19,000	19,000
14. Bag filter system	1	14,000 cfm, automatic fabric dust collectors, bag support, shaker system, isolation damper, external shaker motor and drive, dust hopper, motor and fan for bag filter system (½ in materials handling area)	0.68	Chem. Engr. 3-24-69 Guthrie	7,926	Richardson Engr. Services	1973	8,500	8,500
Subtotal									378,700

Table 46. Limestone Slurry Process (Cont.)

Area 3 Particulate Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Tank, particulate scrubber, effluent hold	4	25,700 gal, 3,435 ft^3, 13′ diameter x 26′ high, open top, (4) 1′ wide baffles, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	13,500	GATX	1971	16,300	65,200
Lining		¼″ neoprene lining			10,000	GATX	1971	12,000	48,000
2. Agitator, effluent hold tank	4	5 hp, neoprene coated	0.26 0.50	Fund. of Cost Engr. 1964 Chem. Engr. 3-24-69 Guthrie	3,400	Mixing Equip. Co.	1971	4,000	16,000
3. Pumps, recycle slurry	6	4,900 gpm, 144′ head, centrifugal, belt drive, 300 hp motor included, carbon steel, neoprene lining		Depends on gpm and head requirements resulting in changes of motor and impeller size	13,440	Denver Equip. Co.	1973	14,500	87,000
4. Venturi scrubber	4	With variable throat, 36′ long x 5′ wide x 20′ high, conveying section & throat carpenter 20, remainder ¼″ carbon steel with neoprene lining	0.60	Universal Oil Products	133,000	Universal Oil Products	1971	150,000	600,000
5. Venturi & MBA sump	4	28′ long x 41′ wide x 13′ high, ¼″ carbon steel, neoprene lining (½ in SO_2 scrubbing area)	0.68	Chem. Engr. 3-24-69 Guthrie	49,500	Universal Oil Products	1971	57,500	230,000
6. Soot blowers	20		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
Subtotal									1,126,200

Table 46. Limestone Slurry Process (Cont.)

Area 4 – SO_2 Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. TCA scrubber	4	SO_2 absorber, mobile bed, with demister, 41′ long x 13′ wide x 41′ high; ¼″ carbon steel with neoprene lining, 316 S.S. grids, high density poly. spheres, FRP spray headers, chevron vane mist eliminators	0.80	Universal Oil Products	254,500	Universal Oil Products	1971	300,000	1,200,000
2. Venturi & MBA sump	4	28′ long x 41′ wide x 13′ high, ¼″ carbon steel, neoprene lining (½ in particulate scrubbing area)	0.68	Chem. Engr. 3-24-69 Guthrie	49,500	Universal Oil Products	1971	57,500	230,000
3. Tank, absorber effluent hold	4	240,000 gal, 32,088 ft^3 40′ diameter x 26′ high, open top, field erected, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	38,327	GATX	1972	45,100	180,400
Lining		¼″ neoprene lining			32,000	GATX	1972	38,600	154,400
4. Agitator, SO_2 absorber hold tank	4	50 hp, neoprene coated	0.50	Chem. Engr. 3-24-69 Guthrie	12,245	Catalytic Inc.	1973	13,250	53,000
5. Pumps, SO_2 absorber recycle slurry	10	11,500 gpm, 105′ head, centrifugal, neoprene lined, belt drive, 500 hp motor included	Depends on gpm and head requirements resulting in changes of motor and impeller size		23,000	Allen, Sherman, Hoff	1971	27,100	271,000
6. Pumps, makeup water	2	1,240 gpm, 150′ head, vertical multistage turbine, 100 hp motor included	Depends on gpm and head requirements resulting in changes of motor and impeller size		2,369	Richardson Engr. Services	1973	2,600	5,200
7. Soot blowers	40		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	160,000
Subtotal									2,254,000

Area 5 – Reheat

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Gas reheater	4	Tube type, 2,028 ft^2 13,900 lb, ½ of tubes made of inconel 625 and remaining ½ made of cor-ten	0.80	Chem. Engr. 3-24-69 Guthrie	70,000	Widows Creek – TVA	1971	82,500	330,000
2. Soot blowers	20		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
Subtotal									410,000

Table 46. Limestone Slurry Process (Cont.)

Area 6 – Gas Handling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Fan	4	41" 1,200 rpm, 2,905 bhp, 3,250 hp motor included with insulation. (Cost is difference between 41" and 15" fan. Remainder is allocated to boiler.)	0.68	Chem. Engr. 3-24-69 Guthrie	59,710	Widows Creek TVA	1971	71,150	284,600
Subtotal									284,600

Area 7 – Solids Disposal

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Pond feed tank	1	63,000 gal, field erected, 8,423 ft^3, 21′ diameter x 26′ high, vertical with open top, carbon steel, 1′ - 8″ x 26′ baffles	0.68	Chem. Engr. 3-24-69 Guthrie	20,000	GATX	1971	24,000	24,000
Lining		¼" neoprene lining			16,120	GATX	1971	19,000	19,000
2. Agitator	1	7½ hp, neoprene coated	0.50 0.47	Chem. Engr. 3-24-69 Fund of Cost Engr. 1964	4,717	Mixing Equip. Co., Inc.	1971	5,400	5,400
3. Pumps, pond feed tank[a]	4	1,128 gpm @ 75′ head, neoprene lined with 50 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller size		1,850	Denver Equip. Co.	1973	2,225	8,900
4. Pumps, recycle pond water[a]	2	1,000 gpm @ 150′ head, multistage turbine, cast iron bowl, stainless steel impellers, with 75 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller size		1,100	Richardson Engr. Services	1973	1,450	2,900
Subtotal									60,200

[a] Cost for this equipment prorated for fly ash removal.

Area 8 – Utilities

Note: There is no process equipment in this area.

Area 9 – Services

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Payloader	1	Gasoline type, 2 yd^3	–	–	21,000	Chem. Engr.– 3-24-69, Guthrie	1969	24,800	24,800
2. Plant vehicles	–	(allocation)	–	–	10,000	–	1974	–	10,000
3. Maint. & instrument shop – equipment	–	Office, machine tools, and machine shop equipment	–	–	22,400	Chem. Engr.– 3-24-69, Guthrie	1969	26,400	26,400
4. Service building – equipment	–	Equipment for lab., locker room, motor control room, restrooms	–	–	29,700	Chem. Engr.– 3-24-69, Guthrie	1969	35,000	35,000
5. Stores – equipment	–	Office equipment, shelving, etc.	–	–	9,000	Chem. Engr.– 3-24-69, Guthrie	1969	10,600	10,600
Subtotal									106,800

Table 47. Lime Slurry Process Equipment List and Cost

Area 1 Raw Material Handling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Conveyor (belt) No. 1	1	Enclosed, 69.3 tons/hr, 18″ belt, 800′ long, 250 ft/min, 58′ rise with 15 hp motor	0.65	Chem. Engr. 3-24-69 Guthrie	30,300	TVA	1973	32,800	32,800
2. Conveyor (belt) No. 2	1	Enclosed, 69.3 tons/hr, 18″ belt, 39′ long, with 3 trippers, 250 ft/min, with 7½ hp motor	0.65	Chem. Engr. 3-24-69 Guthrie	47,800	TVA	1973	51,700	51,700
3. Storage bin, lime	4	11,820 ft^3, 325 tons field erected, 29½′ x 11′ x 30½′, column height 22′, with ladders, C/S	0.68	Chem. Engr. 3-24-69 Guthrie	43,765	Rex Chain Belt, Inc.	1973	50,000	200,000
4. Feeder, discharge	4	Rotary air lock type, 46.2 tons/hr, 18″ diameter by 18″ long, 16 rpm	0.58	Chem. Engr. 3-24-69 Guthrie	3,100	Richardson Engr. Services	1973	3,300	13,200
5. Conveyor elevator	1	Redler Z type, 103′ long, 46.2 tons/hr 5 hp motor	0.65	Chem. Engr. 3-24-69 Guthrie	11,300	TVA work order DO5N71	1964	17,200	17,200
6. Process bin, lime	1	3,360 ft^3, 11′ x 30½′ x 4½′, C/S	0.65	Chem. Engr. 3-24-69 Guthrie	23,400	Rex Chain Belt, Inc.	1973	25,300	25,300
7. Feeder, bin discharge	2	Rotary air lock type, 9″ diameter by 9″ long, carbon steel	0.58	Chem. Engr. 3-24-69 Guthrie	1,400	Richardson Engr. Services	1973	1,500	3,000
8. Bin vibrators	16	National Air Vibrator Co., BH-5			290	National Vibrator Co.	1973	300	4,800
9. Bin vibrators	8	National Air Vibrator Co., BH-4			190	National Vibrator Co.	1973	200	1,600
Subtotal									349,600

Table 47. Lime Slurry Process (Cont.)

Area 2 Feed Preparation

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Conveyor (screw)	2	5.8 tons/hr, 9" diameter feeder screw, 12" diameter conveyor, 12' long, 20 rpm, with 1 hp motor	0.80	Chem. Engr. 3-24-69 Guthrie	2,200	Chem. Engr. 3-24-69, Guthrie	1969	2,900	5,800
2. Slaker, lime	2	11,550 lb/hr, 20' x 5½' x 9', neoprene lined	0.57	Dixie-Cahaba	14,000	Dixie-Cahaba	1973	15,100	30,200
3. Pumps, slaker product	3	185 gpm, 35' head centrifugal, with 5 hp motor, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,200	Denver Equip. Co.	1973	2,400	7,200
4. Slurry feed tank	1	177,600 gal, 23,743 ft^3, 31' diameter by 32' high vertical cylinder, open top, carbon steel, field erected	0.68	Chem. Engr. 3-24-69 Guthrie	35,000	GATX	1971	48,700	48,700
		Neoprene lining						39,900	39,900
5. Agitator, slurry feed tank	1	15 hp, neoprene coated	0.50	Chem. Engr. 3-24-69 Guthrie	7,750	Catalytic, Inc.	1973	8,400	8,400
6. Pumps, slurry feed tank	2	370 gpm, 20' head, centrifugal, with 5 hp motor, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,060	Denver Equip. Co.	1973	2,200	4,400
Subtotal									144,600

Area 3 Particulate Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Particulate-SO_2 scrubber	4	Variable throat venturi, 28' diameter x 54½' high, Chevron Vane mist eliminators	0.60	Chemico	125,000	Chemico	1971	165,100	660,400
		Neoprene lining						20,900	83,600
2. Pumps, particulate scrubber recycle slurry	10	6,500 gpm, 110' head, centrifugal, neoprene lined with belt drive, guard and 350 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		16,188	Allen, Sherman, Hoff	1971	19,100	191,000
3. Pumps, makeup water	2	663 gpm, 150' head vertical multistage turbine, with 50 hp motor (½ in SO_2 scrubbing area)	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,250	Richardson Engr. Services	1973	700	1,400
4. Soot blowers	20		1.0	TVA	3,500	Widows Creek TVA	1971	4,000	80,000
Subtotal									1,016,400

Table 47. Lime Slurry Process (Cont.)

Area 4 - SO_2 Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. SO_2 absorber	4	Fixed throat venturi 28′ diameter x 54½′ high, Chevron Vane mist eliminator	0.60	Chemico	150,000	Chemico	1971	179,900	719,600
		Neoprene lining						20,900	83,600
2. Pumps, SO_2 absorber recycle slurry	10	6,500 gpm, 110′ head, centrifugal, neoprene lined with belt drive guard, and 350 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		16,188	Allen, Sherman Hoff	1971	19,100	19,100
3. Pumps, makeup water	2	663 gpm, 150′ head, vertical multistage turbine with 50 hp motor (½ in particulate scrubbing area)	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,250	Richardson Engr. Services	1973	700	1,400
4. Soot blowers	20		1.0	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
Subtotal									1,075,600

Area 5 - Reheat

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Gas reheater	4	Tube type, 2,022 ft^2, 13,900 lb, ½ of tubes made of inconel 625, other ½ made of cor-ten	0.80	Chem. Engr. 3-24-69 Guthrie	70,000	Widows Creek – TVA	1971	82,500	330,000
2. Soot blowers	20		1.0	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
Subtotal									410,000

Area 6 - Gas Handling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Fan	4	41″, 1,200 rpm, 2,905 bhp, 3,250 hp motor included, with insulation (cost is difference between 41″ and 15″ fan, remainder allocated to boiler)	0.68	Chem. Engr. 3-24-69 Guthrie	60,350	Widows Creek – TVA	1971	71,150	284,600
Subtotal									284,600

Table 47. Lime Slurry Process (Cont.)

Area 7 – Solids Disposal

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Pumps, slurry disposal[a]	6	167 gpm, 164′ head, centrifugal, neoprene lined with belt drive, guard and 15 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,440	Denver Equip. Co.	1973	1,560	9,400
2. Pumps, recycle pond water[a]	2	670 gpm, 150′ head, carbon steel bowl, stainless steel impellers, with 50 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		915	Richardson Engr. Services	1973	1,000	2,000
Subtotal									11,400

[a] Cost is prorated 0.6 to SO_2 removal and 0.4 to flyash disposal.

Area 8 – Utilities

Note: There is no process equipment in this area

Area 9 – Services

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Plant vehicles	–	(Allocation)			10,000	–	1974	–	10,000
2. Maint. & instrument shop – equipment	–	Office, machine tools, and machine shop equipment			26,400	Chem. Engr. – 3-24-69, Guthrie	1969	26,400	26,400
3. Service building – equipment	–	Equipment for lab., locker room, motor control room, restrooms			35,000	Chem. Engr. – 3-24-69, Guthrie	1969	35,000	35,000
4. Stores – equipment	–	Office equipment, shelving, etc.			10,600	Chem. Engr. – 3-24-69, Guthrie	1969	10,600	10,600
Subtotal									82,000

Table 48. Magnesia Slurry - Regeneration Process Equipment List and Cost

Area 1 - Raw Material Handling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Coke receiving hopper	1	8′-4″ side, 2′-4″ bottom, 3′ deep, with load bearing grizzly and vibrator, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	2,400	Catalytic Inc.	1973	2,600	2,600
2. Coke conveyor	1	Redler Z type, 58′ long, 15 tons/hr, 25 hp motor	0.65	Chem. Engr. 3-24-69 Guthrie	7,359	TVA work order D05N71	1964	11,200	11,200
3. Coke storage silo	1	15′ diameter x 20.5′ high with 7.5′ cone bottom, 4,132 ft^3 volume, with slide gate for vibrating hopper, carbon steel	0.90	Chem. Engr. 3-24-69 Guthrie		TVA work order D05C30	1965	8,500	8,500
4. Makeup MgO storage silo	1	18′ diameter x 27′ high with 9′ cone bottom, 7,634 ft^3 volume, 3/8″ carbon steel plate, vibrating hopper	0.90	Chem. Engr. 3-24-69 Guthrie		TVA work order D05C30	1965	13,000	13,000
5. Pneumatic conveying system	1	Complete with blower, air, heater, cyclone receiver, receiver filter and pump	0.60	Chem. Engr. 3-24-69 Guthrie	36,900	Fuller Co.	1965	55,600	55,600
6. Sump pump	1	5 gpm, 10′ head, carbon steel, ¼ hp motor included	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		560	Catalytic, Inc.	1973	600	600
Subtotal									91,500

Area 2 - Feed Preparation

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Weigh feeder, makeup MgO	1	300 lb/hr, carbon steel	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	4,500	TVA	1971	5,300	5,300
2. Vibrating feeder, makeup MgO	1	300 lb/hr, carbon steel, Jeffery 2 DTH	0.58	Chem. Engr. 3-24-69 Guthrie	500	Richardson Engr. Services, for a Jeffery 2 DTH	1973	500	500
3. Conveyor-elevator, Mgo	1	Redler Z type, 70′ long, 8½ tons/hr, [illegible] hp motor	0.65	Chem. Engr. 3-24-69 Guthrie	7,700	TVA work order D05N71	1964	11,700	11,700
4. Weigh feeder, recycle MgO	1	8.3 tons/hr carbon steel	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	7,216	Merrick	1972	8,200	8,200
5. Vibrating feeder, recycle MgO	1	8.3 tons/hr carbon steel	0.58	Chem. Engr. 3-24-69 Guthrie	500	Richardson Engr. Services, for a Jeffery 2 DTH	1973	500	500
6. MgO slurrying tank	1	23′ in diameter by 34′ high, 14,126 ft^3 105,672 gal field erected	0.68	Chem. Engr. 3-24-69 Guthrie	28,100	GATX	1971	33,700	33,700
Lining		Neoprene lining for MgO slurrying tank			23,000	GATX	1971	27,900	27,900
7. Agitator	1	20 hp, neoprene coated	0.50 0.47	Chem. Engr. 3-24-69 Fund. of Cost Engr. 1964	7,750	Catalytic, Inc.	1973	8,400	8,400
8. Mgo slurry pumps	2	263 gpm, 10-20 hp included centrifugal, carbon steel, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,500	Denver Equip. Co.	1973	2,700	5,400
Subtotal									101,600

Table 48. Magnesia Slurry - Regeneration Process (Cont.)

Area 3 – Particulate Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Particulate scrubbers	4	Venturi, 28′ diameter, 48½′ high with variable throat, includes mist eliminator	0.60	Chemico	125,000	Chemico	1971	162,100	648,400
		Neoprene lining			15,950			18,800	75,200
2. Surge tanks	4	40,600 gal, carbon steel, 24′ diameter, 12′ high	0.68	Chem. Engr. 3-24-69 Guthrie	13,275	Chicago Bridge and Iron	1970	15,400	61,600
		Neoprene lining			10,450	GATX	1971	12,700	50,800
3. Agitators, surge tank	4	20 hp, neoprene coated	0.50	Mixing Equip. Co.	4,717	Mixing Equip. Co.	1971	5,500	22,000
4. Recycle pumps	6	4,740 gpm, 130′ head, neoprene lined, 300 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		13,440	Denver Equip. Co.	1973	14,500	87,000
5. Underflow pumps to pond	6	113 gpm, 55 psi, neoprene lined, 7½ hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,060	Denver Equip. Co.	1973	2,200	13,200
6. Soot blowers	20		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
7. Pumps, makeup water	2	880 gpm, 150′ head, vertical, multistage turbine with 50 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,290	Richardson Engr. Services	1973	1,400	2,800
8. Neutralization system	1	(Allocation)						30,000	30,000
Subtotal									1,071,000

Area 4 – SO_2 Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. SO_2 absorbers	4	Venturi absorber 28′ in diameter by 48½′ high, mist eliminator	0.60	Chemico	150,000	Chemico	1971	176,900	707,600
		Neoprene lining						18,800	75,200
2. Pumps, recycle	6	6,320 gpm, 100′ head with 300 hp motor, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		15,913	Allen, Sherman, Hoff	1971	18,800	112,800
3. Soot blowers	20		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
Subtotal									975,600

Area 5 – Reheat

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Reheater	4	Steam, tube type, 1,658 ft^2, ½ of tubes made of Incoloy 825, other ½ made of cor-ten	0.80	Chem. Engr. 3-24-69 Guthrie	70,000	Widows Creek – TVA	1971	73,200	292,800
2. Soot blowers	20		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
Subtotal									372,800

Table 48. Magnesia Slurry - Regeneration Process (Cont.)

Area 6 – Gas Handling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Fan	4	39″, 1,190 rpm, No. 1,035 AF, 3,000 hp motor included (cost is difference between 38″ and 15″ fan, remainder allocated to boiler)	0.68	Chem. Engr. 3-24-69 Guthrie	49,200	Widows Creek – TVA	1971	58,000	232,000
		Insulation for fans			625	TVA	1973	675	2,700
Subtotal									234,700

Area 7 – Slurry Processing

Item	No.	Description	Size-cost scale factor	Factor	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Screens	4	Wet screens, housing 4′ long, 5′ wide, 8′ high, DSM screens	0.58	TVA	4,500	Dorr-Oliver	1971	5,300	21,200
2. Liquor tank	1	5,000 gal, 9′ diameter, 10½′ high, neoprene lined	0.30	Chem. Engr. 3-24-69 Guthrie	8,140	Chem. Engr. – 3-24-69, Guthrie	1969	10,700	10,700
3. Liquor pumps	2	1,440 gpm, 75′ head with 50 hp motor, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,500	Denver Equip. Co.	1973	3,800	7,600
4. Conversion tank	1	6,300 gal, 12′ diameter, 7½′ high, stainless steel, field fabricated	0.66	Fund. of Cost Engr. 1964	19,200	Chem. Engr. – 3-24-69, Guthrie	1969	26,100	26,100
5. Agitator	1	20 hp, stainless steel	0.50 0.51	Chem. Engr. 3-24-69 Fund. of Cost Engr. 1964	4,700	Mixing Equip. Co.	1970	5,900	5,900
6. Steam coil	1	1,200 ft^2 area, stainless steel	0.32	Chem. Engr. 3-24-69 Guthrie	2,000	Chem. Engr. – 3-24-69, Guthrie	1968	2,700	2,700
7. Pumps conversion tank	2	340 gpm, 55′ head, 10 hp, neoprene lined	Depends ongpm and head requirements resulting in changes of motor and impeller sizes		2,500	Denver Equip. Co.	1973	2,700	5,400
8. Centrifuges	2	Parallel 36″ x 72″ solid bowl with 200 hp motors, S/S	0.73	Chem. Engr. 3-24-69 Guthrie	86,667	Bird Machine Co.	1971	102,200	204,400
9. Conveyors, screw – horizontal	1	33.2 tons/hr, 16″ screw, 60 rpm, with 5 hp motor, 20 ft. long, stainless steel	0.60 0.77	(Diameter) Chem. Engr. 3-24-69 (Length and diameter) Fund. of Cost Engr. 1964	3,600	Chem. Engr. – 3-24-69, Guthrie	1969	4,700	4,700
10. Conveyors, screw – vertical	1	33.2 tons/hr 16″ screw, 60 rpm, with 5 hp motor, 40 ft long, stainless steel	0.60 0.77	(Diameter) Chem. Engr 3-24-69 (Length and diameter) Fund. of cost Engr. 1964	6,000	Chem. Engr. – 3-24-69, Guthrie	1969	7,900	7,900
11. Condensate tank	1	100 gal, carbon steel	0.82	Fund of Cost Engr. 1964	185	TVA	1973	200	200
12. Condensate pump	1	25 gpm, 200 psig with 5 hp motor, carbon steel	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		460	Richardson Engr. Services	1973	500	500
Subtotal									297,300

Table 48. Magnesia Slurry - Regeneration Process (Cont.)

Area 8 – Cake Drying

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Fluid bed dryer	1	18' diameter by 40' high single-stage, refractory-lined carbon steel dryer with (a) 10' diameter x 16' long, oil-fired, horizontal, refractory-lined, carbon steel combustion chamber, (b) 250-hp blower, and (c) refractory-lined, carbon steel cyclone with a conical bottom	0.60	Dorr-Oliver 1972	350,000	Dorr-Oliver	1971	412,700	412,700
2. Dust collector	1	Fabric dust collector, 12' 5" wide by 45' 8" long by 21' 3" high, 44,400 lb, 57,900 acfm Dustex model No. DW-14-60	0.68	Chem. Engr. 3-24-69 Guthrie	84,800	American Precision Industries, Inc., Dustex Division	1971	100,000	100,000
3. Fan I.D.	1	250 hp	0.68	Chem. Engr. 3-24-69 Guthrie	19,300	Chem. Engr.– 3-24-69, Guthrie	1968	26,600	26,600
4. Conveyor–elevator	1	Redler Z type, 122' long, 19.6 tons/hr, 25 hp	0.65	Chem. Engr. 3-24-69 Guthrie	13,400	TVA work order D05N71	1964	20,400	20,400
5. $MgSO_3$ storage silo with vibrating hopper	1	Silo 26' diameter x 43' high, with 13' cone bottom, 25,489 ft^3 volume, 4,794 ft^2 surface area, 3/8" carbon steel plate	0.90	Chem. Engr. 3-24-69 Guthrie	19,800	TVA work order D05C30	1965	32,200	32,200
Subtotal									591,900

Table 48. Magnesia Slurry - Regeneration Process (Cont.)

Area 9 - MgSO$_3$ Calcination

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Coke weigh feeder	1	218 lb/hr, 2 hp	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	4,500	TVA	1971	5,300	5,300
2. Vibrating feeder	1	218 lb/hr, 1 hp	0.58	Chem. Engr. 3-24-69 Guthrie	500	Richardson Engr. for a 2 DTH	1973	500	500
3. Conveyor-elevator MgO feeder to fluid bed calciner	1	Redler Z type, 84′ long, 20 tons/hr, 25 hp	0.65	Chem. Engr. 3-24-69 Guthrie	9,200	TVA work order D05N71	1964	14,000	14,000
4. Fluid bed calciner	1	16′ diameter x 38′ high 3 stage with cyclone, carbon steel refractory-lined with a 400 hp blower and a refractory-lined carbon steel cyclone with a conical bottom	0.60	Dorr-Oliver 1972	418,000	Dorr-Oliver	1971	492,800	492,800
5. Conveyor elevator Z-type calciner to recycle MgO	1	Redler Z type, 87′ long, 8½ tons/hr, 15 hp	0.65	Chem. Engr. 3-24-69 Guthrie	9,600	TVA work order D05N71	1964	14,500	14,500
6. MgO recycle storage silo	1	26′ diameter x 31′ high with 13′ cone bottom, 18,950 ft^3 volume, 3,814 ft^2 surface area, 3/8″ carbon steel plate	0.90	Chem. Engr. 3-24-69 Guthrie	16,400	TVA work order D05C30	1965	26,700	26,700
7. Vibrating feeder	1	39,400 lb or 19.8 tons/hr, 2 hp	0.58	Chem. Engr. 3-24-69 Guthrie	1,550	Richardson Engr. for a 3 DM	1973	1,700	1,700
8. Dust collector	1	Fabric dust collector 12′-5″ wide, 33′ 8″ long x 21′ 3″ high, 33,200 lb, 40,000 ACFM Dustex DW-14-44	0.68	Chem. Engr. 3-24-69 Guthrie	60,800	American Precision Industries, Inc., Dustex Division	1971	71,700	71,700
9. Weigh feeder	1	19.8 tons/hr, 2 hp	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	7,200	Merrick	1972	8,200	8,200
10. Waste heat boiler	1	System with 22″ diameter x 20′ long heat exchanger 840 ft^2, 30″ diameter x 20′ long feed water tank 16,000 lb/hr	0.67	TVA	24,800	TVA		37,900	37,900
11. Conveyor-elevator dust collector to conveyor elevator to fluid bed calciner	1	Redler Z type 38′ long, 294 lb/hr, 2.5 hp	0.65	Chem. Engr. 3-24-69 Guthrie	4,200	TVA work order D05N71	1964	6,400	6,400
Subtotal									679,700

Table 48. Magnesia Slurry - Regeneration Process (Cont.)

Area 10–98% Sulfuric Acid Production

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Complete H_2SO_4 unit	1	Complete 98% sulfuric acid system	0.70	Dorr-Oliver	642,100	Dorr-Oliver and Chemico	1971	785,300	785,300
Subtotal									785,300

Area 11–Acid Storage and Shipping

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected Equipment each	1974 cost total
1. Sulfuric acid storage tanks	3	500,000 gal carbon steel tanks	0.63	Chem. Engr. 3-24-69 Guthrie	36,400	TVA work order D05C66	1972	41,400	124,100
2. Pumps	2	400 gpm, with 40 hp motor, carbon steel	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,900	Richardson Engr. Services	1973	2,000	4,000
Subtotal									128,100

Area 12–Utilities

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Oil heaters	2		0.85	Chem. Engr. 3-24-69 Guthrie		TVA	1973	1,000	2,000
2. Coil heaters	2	Coil heaters for tanks, C/S	0.32	Chem. Engr. 3-24-69 Guthrie		TVA	1973	1,500	3,000
3. Tank, storage	1	Fuel oil storage tank, 660,000 gal field erected, C/S painting included	0.63	Chem. Engr. 3-24-69 Guthrie	35,500	GATX	1971	42,600	42,600
4. Tank, holding	2	Holding tank 24,000 gal, field erected, C/S	0.30	Chem. Engr. 3-24-69 Guthrie	11,750	GATX	1971	14,100	28,200
5. Pumps, feed	2		Depends on gpm and head requirements resulting in changes of motor and impeller sizes		750	Catalytic, Inc.	1973	800	1,600
6. Pumps, transfer	2		Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,400	Catalytic, Inc.	1973	1,500	3,000
Subtotal									80,400

Area 13–Services

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Plant vehicles	–	(Allocation)	–	–	15,000	–	1974	–	15,000
2. Shop equipment	–	Office, machine tools, machine shop equipment	–	–	26,000	Chem. Engr. 3-24-69 Guthrie	1971	–	30,600
3. Service building equipment	–	Equipment for lab, locker room, motor control room, restrooms	–	–	34,300	Chem. Engr. 3-24-69 Guthrie	1971	–	40,400
4. Stores equipment	–	Office equipment, shelving, etc.	–	–	10,300	Chem. Engr. 3-24-69 Guthrie	1971	–	12,100
Subtotal									98,100

Table 49. Sodium Solution - SO_2 Reduction Process Equipment List and Cost

Area 1 – Makeup Handling and Preparation

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Pneumatic conveying system	1	Complete with blower, air heater, cyclone receiver, receiver filter and pump	0.60	Chem. Engr. 3-24-69 Guthrie (composite)	36,900	Fuller Co.	1965	55,600	55,600
2. Storage bin, soda ash	1	12′ diameter x 36′ high with cone bottom, 4,500 cu ft, carbon steel	0.90	Chem. Engr. 3-24-69 Guthrie	6,800	TVA work order D05C30	1965	10,200	10,200
3. Vibrating feeder	1	34 cu ft/hr, 1.32 tons/hr	0.80	Chem. Engr. 3-24-69 Guthrie	500	Richardson Engr. Services	1973	500	500
4. Weigh feeder	1	1.32 tons/hr, with discharge chute	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	6,000	Vibra Screw, Inc.	1973	6,400	6,400
5. Mixing tank	1	12′ in diameter by 14′ high, 11,800 gal with 4-1′ wide x 14′ long baffles, carbon steel, with flake-line lining-ceilcote	0.30	Chem. Engr. 3-24-69 Guthrie	7,800	GATX	1971	10,200	10,200
6. Agitator	1	3 hp, neoprene coated	0.50 0.21	Chem. Engr. 3-24-69 Fund. of Cost Engr. 1964	1,400	TVA	1970	1,800	1,800
7. Antioxidant feeder	1	45 lb/hr with chute	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	1,800	Vibra Screw, Inc.	1973	1,900	1,900
8. Bin vibrator	2	Syntron model RV-44-B			768	Syntron,FMC Corp.	1973	850	1,700
9. Pump, mixing tank	2	25 gpm, 75′ head, horizontal centrifugal, with 1 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		800	TVA	1970	1,000	2,000
Subtotal									90,300

Table 49. Sodium Solution - SO_2 Reduction Process (Cont.)

Area 2 – Particulate Scrubbing

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Particulate scrubbers	4	Venturi, 28′ diameter, 48½′ high with variable throat, includes mist eliminator	0.60	Chemico	125,000	Chemico	1971	162,100	648,400
		Neoprene lining for above						18,800	75,200
2. Surge tanks	4	40,600 gal carbon steel, 24′ diameter 12′ high	0.68	Chem. Engr. 3-24-69 Guthrie	13,275	Chicago Bridge and Iron	1970	15,400	61,600
		Neoprene lining for above			10,450	GATX	1971	12,700	50,800
3. Agitator, surge tank	4	20 hp, neoprene coated	0.50	Mixing Equipment Co.	4,717	Mixing Equipment Co.	1971	5,500	22,000
4. Recycle pumps	6	4,740 gpm, 130′ head neoprene lined, 300 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		13,440	Denver Equipment Co.	1973	14,500	87,000
5. Underflow pumps to pond	6	113 gpm, 55 psi, neoprene lined, 7½ hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,060	Denver Equipment Co.	1973	2,200	13,200
6. Neutralization system	1	(Allocation)						30,000	30,000
7. Soot blowers	20		1.00	TVA	3,500	Widows Creek – TVA	1971	4,000	80,000
8. Pumps, make up water	2	880 gpm, 150′ head, verticle, multistage turbine witl 50 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,290	Richardson Engr. Services	1973	1,400	2,800
Subtotal									1,071,000

Table 49. Sodium Solution - SO_2 Reduction Process (Cont.)

Area 3 – SO_2 Absorption

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. SO_2 absorber	4	31′ diameter, 60′ high, carbon steel with S/S internals, fleximesh mist eliminator with fiberglass lining	0.80	Fund. of Cost Engr. 1964	480,000	Koch Engr. Co.	1973	519,350	2,077,400
		Neoprene lining for above					1973	13,525	54,100
2. Recycle pumps	16	1,000 gpm 60′ head with 35 hp motor, centrifugal, neoprene lined	Depends on gpm and head requirements resulting in change of motor and impeller sizes		2,895	Denver Equip. Co.	1973	3,132	50,100
Subtotal									2,181,600

Area 4 – Reheat

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Reheater	4	Steam, tube type, 1,752 sq ft, ½ tubes inconel 625, ½ tubes cor-ten	0.80	Chem. Engr. 3-24-69 Guthrie	70,000	Widows Creek–TVA	1971	82,500	330,000
2. Soot blowers	20		1.00	TVA	3,500	Widows Creek–TVA	1971	4,000	80,000
Subtotal									410,000

Area 5 – Flue Gas Handling (Fans and Ducts)

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Fan	4	41.5″, 1,200 rpm, 3,500 hp motor included (cost is difference between 41.5″ and 15″ fan, remainder allocated to boiler)	0.68	Chem. Engr. 3-24-69 Guthrie	59,700	Widows Creek–TVA	1971	70,400	281,600
		Insulation for fans			700	TVA	1973	750	3,000
Subtotal									284,600

Table 49. Sodium Solution - SO_2 Reduction Process (Cont.)

Area 6 Purge Treatment

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Refrigeration system	1	500 tons	0.72	Fund. of Cost Engr. 1964	49,700	Trane	1973	53,800	53,800
2. Pumps, etheylene glycol	2	2,607 gpm, 125′ head horizontal, centrifugal, with 200 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		6,306	Richardson Engr. Services	1973	6,800	13,600
3. Tank, etheylene glycol	1	10′ diameter, 15′ high with top 8,813 gal., insulated	0.30	Chem. Engr. 3-24-69 Guthrie	7,000	Chem. Engr. 3-24-69, Guthrie	1969	9,800	9,800
		Insulation for above						500	500
4. Tank, chiller-crystallizer	1	12′ diameter, 18′ high, ¼″ S/S plate, insulated	0.65	Chem. Engr. 3-24-69 Guthrie	120,000	Platecoil Co.	1973	129,800	129,800
		Insulation for above						500	500
5. Pumps, chiller-crystallizer	2	350 gpm, 50′ head horizontal, centrifugal, neoprene lined, with 10 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,000	Denver Equip. Co.	1973	3,250	6,500
6. Feed cooler	1	1,529 ft^2, shell and tube, 316 S/S	0.65	Chem. Engr. 3-24-69 Guthrie	45,000	Chem. Engr. 3-24-69, Guthrie	1969	47,500	47,500
7. Centrifuge	1	36″ diameter, 96″ solid bowl, 316 S/S with 300 hp drive	0.73	Chem. Engr. 3-24-69 Guthrie	108,400	Bird Machine Co.	1971	130,000	130,000
8. Tank, centrate	1	5′ diameter, 8′ high 960 gal,closed top, S/S	0.30	Chem. Engr. 3-24-69 Guthrie	6,400	Chem. Engr. 3-24-69, Guthrie	1969	8,800	8,800
9. Pumps, centrate	2	350 gpm, 75′ head, horizontal, centrifugal, neoprene lined with 15 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,500	Denver Equipment Co.	1973	3,800	7,600
10. Belt conveyor, centrifuge and recycle to dryer	1	18″ belt, 14′ long, 50 tons/hr, 100 ft/min with 1 hp motor	0.65 0.23	Chem. Engr. 3-24-69 Fund. of Cost Engr. 1964	1,850	TVA	1973	2,000	2,000
11. Dryer, rotary	1	12′ diameter, 60 long, with 175 hp motor	0.45 0.92	Chem. Engr. 3-24-69- Fund of Cost Engr. 1964	120,000	TVA	1971	141,500	141,500
12. Belt conveyor, dryer to elevator	1	18″ belt, 14′ long, 50 tons/hr 100 ft/min with 1 hp enclosed motor	0.65	Chem. Engr. 3-24-69 Fund of Cost Engr. 1964	2,300	TVA	1973	2,500	2,500
13. Bucket elevator	1	49′ high, 50 tons/hr, 10″ x 6″ x 6¼″ bucket, 260 ft/min with 7.5 hp motor	0.83	Chem. Engr. 3-24-69 Guthrie	4,100	TVA	1964	6,200	6,200
14. Weigh feeder, recycle bin	1	30 tons/hr, 100 ft/min, 18″ belt, 5′ long, with 1 hp motor	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	7,400	TVA	1973	8,000	8,000

Table 49. Sodium Solution - SO_2 Reduction Process (Cont.)

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
15. Bin, recycle	1	100 ft^3, C/S closed top	0.68	Chem. Engr. 3-24-69 Guthrie	1,850	TVA	1973	2,000	2,000
16. Feeder, vibrating	1	30 tons/hr	0.65 (conveyor)	Chem. Engr. 3-24-69 Guthrie	1,850	TVA	1973	2,000	2,000
17. Conveyor, recycle	1	18" belt, 30 tons/hr, 95' long, enclosed with 1 hp motor	0.65 0.50	Chem. Engr. 3-24-69 Fund. of Cost Engr. 1964	4,600	TVA	1973	5,000	5,000
18. Dust collector	1	Fabric dust collector 12'-5" wide, 45'-8" long, 21'-3" high, 44,400 lb, 57,900 acfm, Dustex model DW-14-60	0.68	Chem. Engr. 3-24-69 Guthrie	84,800	American Precision Industries Inc., Dustex Division	1971	100,000	100,000
19. Fan, dust collector	1	Fan for above 250 hp	0.68	Chem. Engr. 3-24-69 Guthrie	19,300	Chem. Engr. – 3-24-69, Guthrie	1968	26,600	26,600
20. Steam/air heater	1	Air heater, finned tube, 735 ft^2 insulated, without motor fan, C/S	0.80	Chem. Engr. 3-24-69 Guthrie	5,800	Chem. Engr. – 3-24-69, Guthrie	1969	8,500	8,500
21. Dust conveyor No. 1	1	14" belt, 2 tons/hr, 45' long, covered, with 1 hp motor	0.65 0.50	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	4,600	TVA	1973	5,000	5,000
22. Dust conveyor No. 2	1	14" belt, 2 tons/hr, 30' long, covered, with 1 hp motor	0.65 0.23	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	3,700	TVA	1973	4,000	4,000
23. Belt conveyor, storage bin loading	1	14" belt, 2 tons/hr, 68' long, enclosed, with 3 hp motor	0.65 0.23	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	2,775	TVA	1973	3,000	3,000
24. Bin, storage, and loading	1	20' wide, 40' high, 10' deep, with cone bottom, 8,000 ft^3, carbon steel	0.90	Chem. Engr. 3-24-69 Guthrie	12,200	TVA	1965	18,400	18,400
25. Bin vibrator	4	Syntron model RV-44-B			768	Syntron, FMC Corp.	1973	850	3,400
26. Agitator, chiller-crystallizer	1	5 hp, neoprene coated	0.50 0.46	Chem. Engr. 3-24-69 Fund. of Cost Engr. 1964	1,550	TVA	1970	1,550	2,000
Subtotal									748,500

Table 49. Sodium Solution - SO_2 Reduction Process (Cont.)

Area 7 SO_2 Regeneration

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Surge tank	1	36′ diameter, 38′ high, 278,400 gal, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	41,100	GATX	1972	48,000	48,000
		Lining for above						35,100	35,100
2. Pump, surge tank	2	600 gpm, 125′ head horizontal centrifugal with 40 hp motor, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,400	Denver Equip. Co.	1973	3,700	7,400
3. Evaporator-crystallizer system (complete)	2	Shell and tube heater, evaporator-crystallizer, pumps-evap. circulation, primary condensers	0.70	Chem. Engr. 3-24-69 Guthrie	600,000	Goslin	1973	649,200	1,298,400
4. Stripper	2	2′-8″ diameter, 16′ high, 316 stainless steel	0.79	Fund. of Cost Engr. 1964	9,600	TVA	1973	10,400	20,800
5. Dissolving tank	2	36′ diameter, 20′ high, 152,280 gal, carbon steel, resin lined	0.68	Chem. Engr. 3-24-69 Guthrie	21,000	GATX	1972	23,850	47,700
		Lining for above						23,150	46,300
6. Agitator, dissolving tank	2	10 hp, neoprene coated	0.46 0.50	Chem. Engr. 3-24-69 Guthrie Fund. of Cost Engr. 1964	4,717	Mixing Equip. Co.	1971	5,500	11,000
7. Pumps, dissolving tank	2	600 gpm, 100′ head, horizontal, centrifugal, neoprene lined	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,400	Denver Equip. Co.	1973	3,700	7,400
8. Compressor	2	1,268 scfm with 250 hp drive	0.90	Fund. of Cost Engr. 1964	42,260	Turbo-netics	1974	43,950	87,900
9. Condensate tank	1	10′ diameter, 16′ long, horizontal, 9,408 gal, insulated carbon steel	0.30	Chem. Engr. 3-24-69 Guthrie	6,000	Chem. Engr. 3-24-69, Guthrie	1969	8,300	8,300
		Insulation for above						500	500
10. Condensate pumps	2	600 gpm, 125′ head, horizontal, centrifugal, with 30 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,575	Richardson Engr. Services	1973	1,700	3,400
11. Desuperheater	1	250,000 lb/hr, with pressure reducing station	0.65	Chem. Engr. 3-24-69 Guthrie	5,100	Copes-Vulcan Inc.	1974	5,300	5,300
Subtotal									1,627,500

Area 8 SO_2 Reduction

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. SO_2 reduction unit	1	Complete unit	0.55	Allied Chemical	1,728,000	Allied Chemical	1973	1,869,700	1,869,700
Subtotal									1,869,700

Table 49. Sodium Solution - SO_2 Reduction Process (Cont.)

Area 9 Sulfur Storage and Shipping

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Tanks, sulfur storage	1	43' diameter, 41' high, 467,109 gal, carbon steel, closed top	0.68	Chem. Engr. 3-24-69 Guthrie	45,000	Chem. Engr. 3-24-69, Guthrie	1969	64,800	64,800
		Insulation for above						10,000	10,000
2. Pumps, sulfur	4	125 gpm, 100 head, high temp., steam traced and insulated, with 10 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,850	TVA	1973	2,000	8,000
3. Sulfur receiving pit	1	10' wide, 10' long, 10' deep, with cover 304 S.S.	0.90	Chem. Engr. 3-24-69 Guthrie	1,600	TVA	1973	17,600	17,600
		Insulation for above						2,400	2,400
Subtotal									102,800

Area 10 Utilities

Note: There is no process equipment in this area

Area 11 Services

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Plant vehicles		(Allocation)			15,000		1974	–	15,000
2. Main. and instrument shop equipment		Office, machine tools and machine shop equipment			26,000	Chem. Engr. 3-24-69, Guthrie	1971	30,600	30,600
3. Service building equipment	–	Equipment for lab, locker room, motor control room, restrooms	–		34,300	Chem. Engr. 3-24-69, Guthrie	1971	40,400	40,400
4. Stores equipment	–	Office equipment, shelving, etc.	–		10,300	Chem. Engr. 3-24-69, Guthrie	1971	12,100	12,100
Subtotal									98,100

Table 50. Catalytic Oxidation Process Equipment List and Cost

Area 1 Startup bypass ducts

Note There is no process equipment in this area

Area 2 Flue gas cleaning

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Precipitator	4	Double compartment high temp., 99.9% efficiency precipitator 75′ high by 100′ wide by 50′ deep 625,000 acfm at 890°F and 8″ H_2O	0.75	Chem. Engr. 3-24-69 Guthrie	1,032,500	TVA	1973	1,117,165	4,468,700
Subtotal									4,468,700

Area 3 SO_2 Conversion

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Converter	4	Converter 50′ high by 33′ wide by 36′ long, plate work, screens, insulation, catalyst discharge, gates, platforms, paint, etc., carbon steel	0.90	TVA	118,200	Stanford Research Institute, Monsanto	1970	146,800	587,200
2. Unloading conveyor	1	55.2 tons/hr, 20″ belt, 250 fpm, 350′ long with 5 hp motor totally enclosed	0.65	Chem. Engr. 3-24-69 Guthrie	11,120	TVA	1973	12,000	12,000
3. Catalyst elevator	1	Bucket elevator 90′ high with 18″ x 8″ x 11 3/4″ buckets and 10 hp motor	0.83	Chem. Engr. 3-24-69 Guthrie	18,200	Chem. Engr. 3-24-69, Guthrie	1969	24,000	24,000
4. Catalyst sifter	1	Catalyst sifter 4′ wide by 10′ long single deck screen with 3 hp motor	0.55	TVA	3,000	Stanford Research Institute, Monsanto	1970	3,700	3,700
5. Hopper, fly ash collection	1	Hopper 8′ diameter by 16′ high with 8′ cone, 938 ft^3 with closed top, carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	3,700	TVA	1973	4,000	4,000
6. Catalyst storage bin	1	Bin, 18′ diameter by 25′ high with 15′ cone, 7,634 ft^3 with closed top, carbon steel	0.68	Chem. Engr. 3-24-69	8,800	TVA	1973	9,500	9,500
7. Catalyst loading conveyor	1	Belt conveyor 260′ with tripper, 20″ belt and 25 hp motor enclosed	0.65	Chem. Engr. 3-24-69 Guthrie	28,120	TVA	1973	30,400	30,400
Subtotal									670,800

Table 50. Catalytic Oxidation Process (Cont.)

Area 4 Heat Recovery

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Economizer	4	Economizer 6.9′ wide by 33.5′ high by 8.4′ long, finned tube gas to water heat exchanger	0.80	TVA					N/C
2. Air heater	4	Air heater 6.6′ high by 24.4′ wide by 26.6′ long, 115,600 ft^2, gas to air heat exchanger (as compared to 158,400 ft^2 each required for normal power plant operation–credit for power plant is assumed for uniform comparison with other processes.)	0.80	Chem. Engr. 3-24-69 Guthrie	64,600	Colbert unit No. 5–TVA	1960	(102,700)	(410,800)
3. Steam/air heater	4	Air heater 14.4′ high by 30.2′ wide by 2.22′ long, finned tube steam to air heater, 9,260 ft^2 area	0.80	Chem. Engr. 3-24-69 Guthrie	6,000	Chem. Engr.– 3-24-69, Guthrie	1969	8,800	35,200
4. Fluid/air heater	4	Air heater 14.4′ high by 30.2′ wide by 8.86′ long, finned tube liquid to air heat exchanger 81,730 ft^2 area	0.80	Chem. Engr. 3-24-69 Guthrie	30,000	Chem. Engr.– 3-24-69, Guthrie	1969	43,400	173,600
5. Condensate heater	4	4,034 ft^2 carbon steel shell and tube water to condensate heat exchanger	0.65	Chem. Engr. 3-24-69 Guthrie	23,000	Chem. Engr.– 3-24-69, Guthrie	1969	33,200	132,800
6. Surge tank	2	Cooling water surge tank-No. 2 acid cooler, vertical cylinder, 8,136 gal., carbon steel open top	0.30	Chem. Engr. 3-24-69 Guthrie	6,300	Chem. Engr.– 3-24-69, Guthrie	1969	8,700	17,400
7. Pump recirculating	6	Condensate heater tank pump and drive, 1,356 gpm @ 162′ head, centrifugal with 100 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,275	Richardson Engr. Services	1973	3,500	21,000
Subtotal									(30,800)

Area 5–Fans

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. F. D. Fan	4	16.5″, 270,000 cfm with 1,000 hp motor	0.68	Chem. Engr. 3-24-69 Guthrie					N/C
2. I. D. Fan	4	46″, 393,000 cfm with 3,750 hp motor (cost is difference between 46″ and 15″ fan, remainder allocated to boiler)	0.68	Chem. Engr. 3-24-69 Guthrie	66,900	Widows Creek–TVA	1971	78,875	315,500
Subtotal									315,500

Table 50. Catalytic Oxidation Process (Cont.)

Area 6 – Sulfuric Acid Absorption and Cooling

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Absorber and mist eliminator	2	Vertical, cylindrical, brick-lined, packed with Brink fiber demister	0.90	TVA	1,538,500	Monsanto	1970	1,910,850	3,821,700
2. Pumps, acid circulation	10	65 psig, 905.5 gpm, with 60 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,417	Richardson Engr. Services	1973	3,700	37,000
3. No. 1 circulation acid cooler	8	Acid to fluid heat exchanger, impervious graphite tubes, 12,200 ft^2, carbon steel shell	0.65	Chem. Engr. 3-24-69 Guthrie	133,000	Karbate	1971	156,800	1,254,400
		Insulation for above						3,000	24,000
4. Tank, coolant surge	2	Cooling solution surge tank, vertical cylinder, 7,506 gal, carbon steel	0.30	Chem. Engr. 3-24-69 Guthrie	6,000	Chem. Engr. – 3-24-69, Guthrie	1968	8,300	16,600
5. Pumps, coolant recirculation	6	85 psig, 1,251 gpm, with 125 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		3,893	Richardson Engr. Services	1973	4,200	25,200
6. No. 2 circulation acid cooler	4	Acid to water heat exchanger, impervious graphite tubes, 8,070 ft^2, carbon steel shell	0.65	Chem. Engr. 3-24-69 Guthrie	95,000	Karbate	1971	114,000	456,000
7. Product acid cooler	2	Shell and tube acid to water heat exchanger, impervious graphite tubes, 165 ft^2, carbon steel shell	0.65	Chem. Engr. 3-24-69 Guthrie	4,500	Karbate	1971	5,300	10,600
8. Tank, intermittent wash	1	8,000 gal, 10′ diameter by 13.5′ high carbon steel, open top	0.30	Chem. Engr. 3-24-69 Guthrie	6,200	Chem. Engr. – 3-24-69, Guthrie	1968	8,500	8,500
9. Pumps, intermittent wash	2	800 gpm, 100′ head with 40 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		2,400	Richardson Engr. Services	1973	2,600	5,200
Subtotal									5,659,200

Table 50. Catalytic Oxidation Process (Cont.)

Area 7 Acid Storage and Shipping

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Product acid storage tank	4	50′ diameter by 35′ high vertical cylinder, 500,000 gal carbon steel	0.68	Chem. Engr. 3-24-69 Guthrie	14,200	TVA work order D05C66	1972	16,100	64,400
2. Acid loading pumps	2	400 gpm pumps, with 40 hp motor	Depends on gpm and head requirements resulting in changes of motor and impeller sizes		1,893	Richardson Engr. Services	1973	2,000	4,000
Subtotal									68,400

Area 8 Utilities

Note: There is no process equipment in this area.

Area 9 Services

Item	No.	Description	Size-cost scale factor	Factor source	Base cost	Base cost source	Date of cost	Projected equipment each	1974 cost total
1. Vehicles	–	(Allocation)	–	–	10,000	–	1974	–	10,000
2. Shop building equipment		Maintenance and instrumentation shop equipment (allocation)	–	–	26,400	–	1974	–	26,400
Subtotal									36,400

Table 51. Limestone Slurry Process
Total Average Annual Operating Costs Summary[a]

Case Coal-fired unit	Years remaining life	Total annual operating cost, $	Dollars/ton (bbl) of coal (oil) burned	Mills/ kWh	Cents/ million Btu heat input	Dollars/ ton sulfur removed
90% SO_2 removal; on-site solids disposal						
200 MW N 3.5% S	30	3,921,500	7.31	2.80	30.45	267.31
200 MW E 3.5% S	20	3,867,100	6.98	2.76	29.08	255.25
500 MW E 3.5% S	25	7,892,600	5.88	2.26	24.51	215.17
500 MW N 2.0% S	30	6,774,700	5.16	1.94	21.51	330.47
500 MW N 3.5% S	30	7,702,700	5.87	2.20	24.45	214.68
500 MW N 5.0% S	30	8,522,200	6.49	2.43	27.05	166.25
1,000 MW E 3.5% S	25	12,752,900	4.86	1.82	20.24	177.72
1,000 MW N 3.5% S	30	11,874,100	4.68	1.70	19.50	171.17
80% SO_2 removal; on-site solids disposal						
500 MW N 3.5% S	30	7,378,000	5.62	2.11	23.42	231.36
90% SO_2 removal; off-site solids disposal						
500 MW N 3.5% S	30	8,376,500	6.38	2.39	26.59	233.46
90% SO_2 removal; on-site solids disposal (existing unit requiring particulate scrubber)						
500 MW E 3.5% S	25	9,573,400	7.14	2.74	29.73	261.00
Oil-fired power unit						
90% SO_2 removal; on-site solids disposal						
200 MW N 2.5% S	30	2,842,000	1.38	2.03	22.07	362.96
500 MW N 1.0% S	30	4,732,500	0.94	1.35	15.02	618.63
500 MW N 2.5% S	30	5,564,400	1.11	1.59	17.66	290.87
500 MW N 4.0% S	30	6,281,800	1.25	1.79	19.94	205.1[illegible]
500 MW E 2.5% S	25	6,587,300	1.28	1.88	20.46	336.77
1,000 MW N 2.5% S	30	8,987,400	0.92	1.28	14.76	242.97

[a] Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.
Limestone raw material cost, $4/ton.
Trucking and off-site costs for calcium solids disposal, $4/ton.

Table 52. Lime Slurry Process
Total Average Annual Operating Costs Summary[a]

Case Coal-fired power unit	Years remaining life	Total annual operating cost, $	Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
90% SO_2 removal; on-site solids disposal						
200 MW N 3.5% S	30	4,163,900	7.76	2.97	32.33	283.84
200 MW E 3.5% S	20	4,822,000	8.70	3.44	36.26	318.28
500 MW E 3.5% S	25	9,612,400	7.16	2.75	29.85	262.06
500 MW N 2.0% S	30	6,915,100	5.27	1.98	21.95	337.32
500 MW N 3.5% S	30	8,101,900	6.17	2.31	25.72	225.81
500 MW N 5.0% S	30	9,170,100	6.99	2.62	29.11	178.89
1,000 MW E 3.5% S	25	15,301,400	5.83	2.19	24.29	213.23
1,000 MW N 3.5% S	30	12,553,100	4.95	1.79	20.61	180.96
80% SO_2 removal; on-site solids disposal						
500 MW N 3.5% S	30	7,806,900	5.95	2.23	24.78	244.81
90% SO_2 removal; off-site solids disposal						
500 MW N 3.5% S	30	8,641,000	6.58	2.47	27.43	240.83
90% SO_2 removal; on-site solids disposal (existing unit requiring particulate scrubber)						
500 MW E 3.5% S	25	9,728,300	7.25	2.78	30.21	265.22
Oil-fired power unit						
90% SO_2 removal						
200 MW N 2.5% S	30	3,413,500	1.66	2.44	26.50	435.95
500 MW N 1.0% S	30	5,748,600	1.14	1.64	18.25	751.45
500 MW N 2.5% S	30	6,852,800	1.36	1.96	21.75	358.22
500 MW N 4.0% S	30	7,742,300	1.54	2.21	24.58	252.85
500 MW E 2.5% S	25	8,001,500	1.56	2.29	24.85	409.07
1,000 MW N 2.5% S	30	10,795,200	1.11	1.54	17.73	291.84

[a] Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.
Trucking and off-site costs for calcium solids disposal, $4/ton.

**Table 53. Magnesia Slurry - Regeneration Process
Total Average Annual Operating Costs Summary[a]**

Case Coal-fired power unit	Years remaining life	Total annual operating cost, $	Dollars/ton 100% H_2SO_4	Dollars/ton (bbl) of coal (oil) burned	Mills/ kWh	Cents/ million Btu heat input	Dollars/ ton sulfur removed
90% SO_2 removal							
200 MW N 3.5% S	30	4,776,800	105.68	8.90	3.41	37.09	323.85
200 MW E 3.5% S	20	5,091,200	109.25	9.19	3.64	38.28	334.29
500 MW E 3.5% S	25	9,607,900	85.10	7.16	2.75	29.84	260.66
500 MW N 2.0% S	30	7,523,400	119.23	5.73	2.15	23.88	365.04
500 MW N 3.5% S	30	9,210,800	83.43	7.02	2.63	29.24	255.43
500 MW N 5.0% S	30	10,768,500	68.24	8.20	3.08	34.19	209.02
1,000 MW E 3.5% S	25	15,481,900	70.09	5.90	2.21	24.57	214.64
1,000 MW N 3.5% S	30	14,347,000	67.20	5.65	2.05	23.56	205.78
80% SO_2 removal							
500 MW N 3.5% S	30	8,789,700	89.51	6.70	2.51	27.90	274.16
90% SO_2 removal (existing unit requiring particulate scrubber)							
500 MW E 3.5% S	25	11,227,300	99.44	8.37	3.21	34.87	304.59
Oil-fired power unit							
90% SO_2 removal							
200 MW N 2.5% S	30	3,204,400	132.96	1.56	2.29	24.88	407.17
500 MW N 1.0% S	30	4,633,100	196.32	0.92	1.32	14.71	602.48
500 MW N 2.5% S	30	6,092,700	103.44	1.21	1.74	19.34	316.83
500 MW N 4.0% S	30	7,393,500	78.49	1.47	2.11	23.47	240.28
500 MW E 2.5% S	25	7,308,700	121.41	1.42	2.09	22.70	371.75
1,000 MW N 2.5% S	30	9,715,900	85.30	1.00	1.39	15.95	261.32

[a] Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.

Table 54. Sodium Solution - SO_2 Reduction Process
Total Average Annual Operating Costs Summary[a]

Case Coal-fired power unit	Years remaining life	Total annual operating cost, $	Dollars/ton product sulfur	Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
90% SO_2 removal							
200 MW N 3.5% S	30	5,971,700	446.65	11.13	4.27	46.36	407.07
200 MW E 3.5% S	20	7,377,700	534.62	13.31	5.27	55.47	486.98
500 MW E 3.5% S	25	14,658,000	438.60	10.92	4.19	45.52	399.62
500 MW N 2.0% S	30	9,101,700	487.24	6.93	2.60	28.89	443.99
500 MW N 3.5% S	30	11,601,500	354.79	8.84	3.31	36.83	323.34
500 MW N 5.0% S	30	13,983,300	299.36	10.65	4.00	44.39	272.79
1,000 MW E 3.5% S	25	25,118,500	384.13	9.57	3.59	39.87	350.03
1,000 MW N 3.5% S	30	18,391,300	290.96	7.25	2.63	30.20	265.12
80% SO_2 removal							
500 MW N 3.5% S	30	10,834,300	372.83	8.25	3.10	34.39	339.74
90% SO_2 removal (existing unit requiring particulate scrubber)							
500 MW E 3.5% S	25	16,389,200	490.40	12.22	4.68	50.90	446.82
Oil-fired power unit							
90% SO_2 removal							
200 MW N 2.5% S	30	4,269,200	598.77	2.07	3.05	33.15	545.24
500 MW N 1.0% S	30	5,854,700	839.99	1.16	1.67	18.59	765.32
500 MW N 2.5% S	30	8,305,100	476.21	1.65	2.37	26.37	434.14
500 MW N 4.0% S	30	10,640,500	381.38	2.11	3.04	33.78	347.50
500 MW E 2.5% S	25	10,261,600	575.85	1.99	2.93	31.87	524.62
1,000 MW N 2.5% S	30	13,686,200	406.00	1.41	1.96	22.47	370.00

[a] Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.

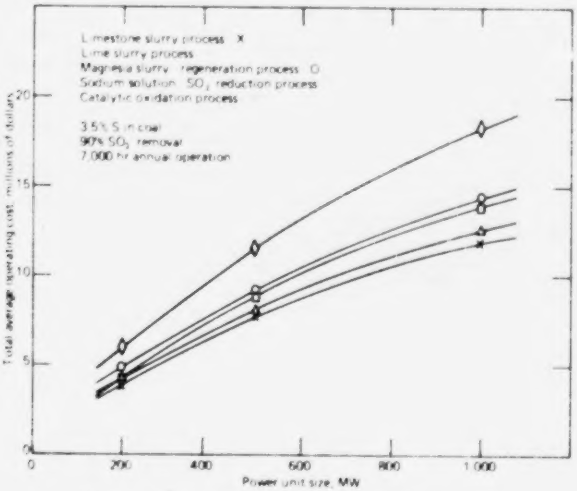


Figure 43. All processes. Effect of power unit size on total average annual operating cost: new coal-fired units under regulated economics

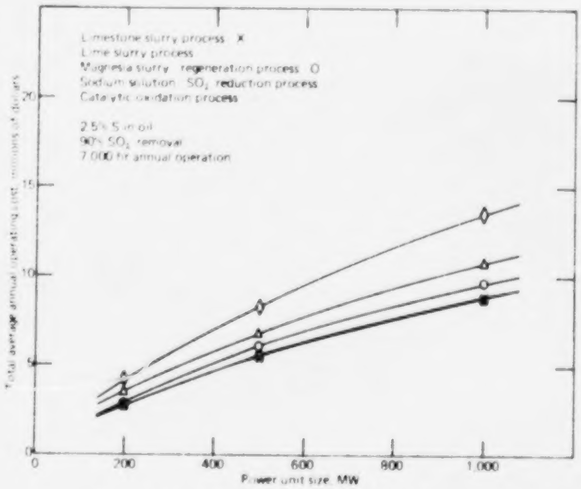


Figure 44. All processes. Effect of power unit size on total average annual operating cost: new oil-fired units under regulated economics

Table 55. Catalytic Oxidation Process Total Average Annual Operating Costs Summary[a]

Case Coal-fired power unit	Years remaining life	Total annual operating cost, $	Dollars/ton 100% H_2SO_4	Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
90% SO_2 removal							
200 MW N 3.5% S	30	4,232,700	94.27	7.89	3.02	32.86	288.53
200 MW E 3.5% S	20	5,849,400	126.06	10.55	4.18	43.98	386.10
500 MW E 3.5% S	25	12,399,600	110.41	9.24	3.54	38.51	338.05
500 MW N 2.0% S	30	8,801,200	140.15	6.71	2.51	27.94	429.33
500 MW N 3.5% S	30	8,873,900	80.75	6.76	2.54	28.17	247.32
500 MW N 5.0% S	30	8,940,500	56.95	6.81	2.55	28.38	174.41
1,000 MW E 3.5% S	25	21,460,800	97.64	8.18	3.07	34.06	299.06
1,000 MW N 3.5% S	30	13,957,600	65.71	5.50	1.99	22.92	201.21
90% SO_2 removal (existing unit without existing particulate collection facilities)							
500 MW E 3.5% S	25	13,598,300	121.09	10.14	3.89	42.23	370.73
Oil-fired power unit							
90% SO_2 removal							
200 MW N 2.5% S	30	2,750,100	114.59	1.34	1.96	21.35	351.23
500 MW N 1.0% S	30	5,743,600	245.45	1.14	1.64	18.23	750.80
500 MW N 2.5% S	30	5,677,500	96.89	1.13	1.62	18.02	296.79
500 MW N 4.0% S	30	5,565,100	59.33	1.11	1.59	17.67	181.75
500 MW E 2.5% S	25	11,126,100	185.74	2.16	3.18	34.55	568.82
1,000 MW N 2.5% S	30	8,911,900	78.66	0.92	1.27	14.63	240.93

[a] Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.

Table 56. Comparison of Average Annual Operating Costs for SO_2 Removal Processes at 90% and 80% SO_2 Removal

	Projected total average annual operating cost, $ 500 MW, new 3.5% S coal-fired units		Annual operating cost savings resulting from design for 80% SO_2 removal compared to 90%	
Process	90% SO_2 removal	80% SO_2 removal	$	%
Limestone slurry	7,702,700	7,378,000	324,700	4.2
Lime slurry	8,101,900	7,806,900	295,000	3.6
Magnesia slurry - regeneration	9,210,800	8,789,700	421,100	4.6
Sodium solution - SO_2 reduction	11,601,500	10,834,300	767,200	6.6

Table 57. Average Annual Operating Cost for SO_2 Removal Installations on Existing Power Units Requiring Additional Facilities for Removal of Particulates–Comparison with Standard

	Projected average annual operating cost, $ 500 MW, existing 3.5% S coal-fired units		Difference in projected annual operating cost	
Process	Requiring additional particulate removal facilities	Standard[a]	$	%
Limestone slurry	9,573,400	7,892,600	1,680,800	21.3
Lime slurry	9,728,300	9,612,400	115,900	1.2
Magnesia slurry - regeneration	11,227,300	9,607,900	1,619,400	16.9
Sodium solution - SO_2 reduction	16,389,200	14,164,500	2,224,700	15.7
Catalytic oxidation	13,598,300	12,399,600	1,198,700	9.7

[a] Standard case assumes that the existing electrostatic precipitator is adequate for existing units.

Table 58. Comparison of Average Annual Operating Costs for Limestone and Lime SO_2 Removal Processes Using On-site and Off-site Waste Solids Disposal

Process	Projected total average annual operating cost, \$ 500 MW, new 3.5% S coal-fired units		Annual operating cost savings resulting from design for on-site as opposed to off-site disposal	
	Off-site disposal	On-site disposal	\$	%
Limestone slurry	8,376,500	7,702,700	673,800	8.0
Lime slurry	8,641,000	8,101,900	539,100	6.2

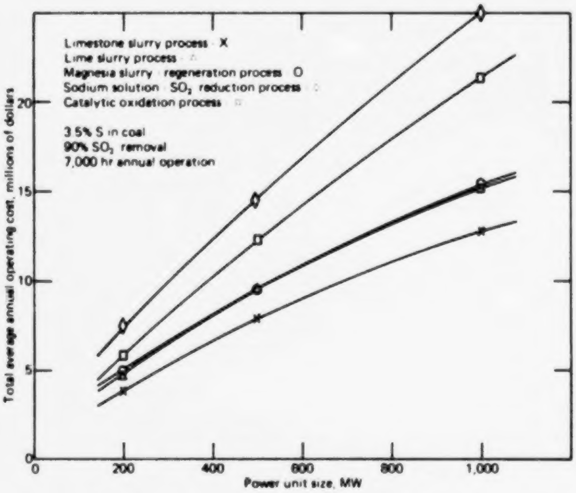


Figure 45. All processes. Effect of power unit size on total average annual operating cost: existing coal-fired units under regulated economics

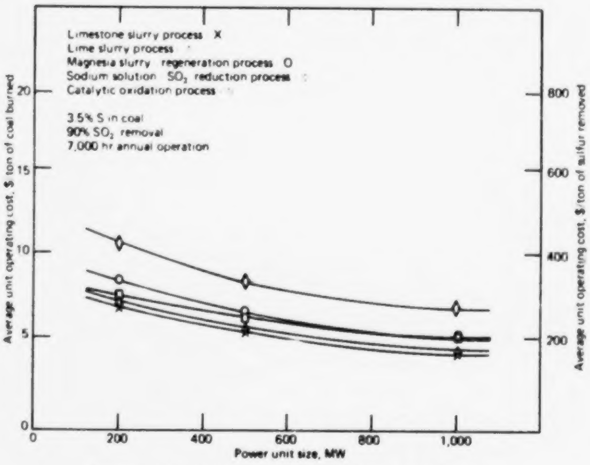


Figure 46. All processes. Effect of power unit size on average unit operating cost: new coal-fired units under regulated economics

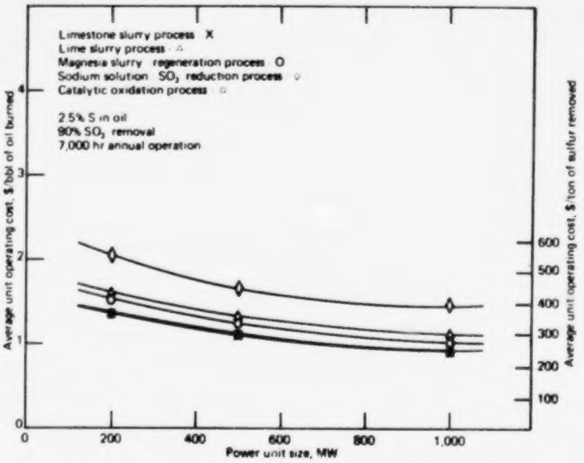


Figure 47. All processes. Effect of power unit size on average unit operating cost: new oil-fired units under regulated economics

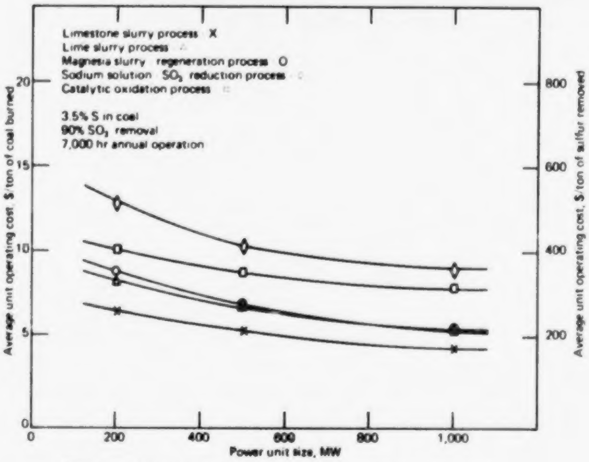


Figure 48. All processes. Effect of power unit size on average unit operating cost: existing coal-fired units under regulated economics

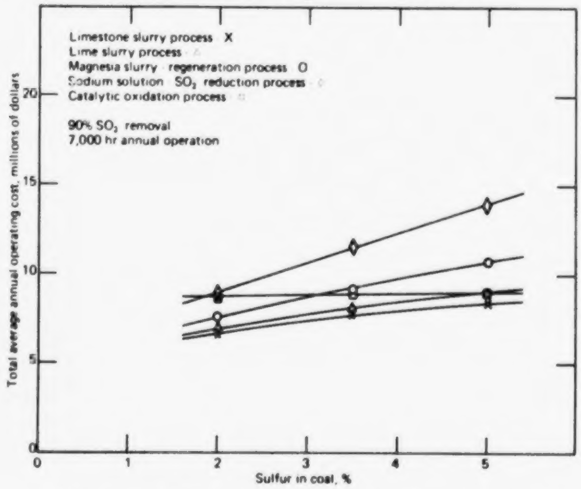


Figure 49. All processes. Effect of sulfur content of coal on total average annual operating cost: new 500-MW coal-fired units under regulated economics.

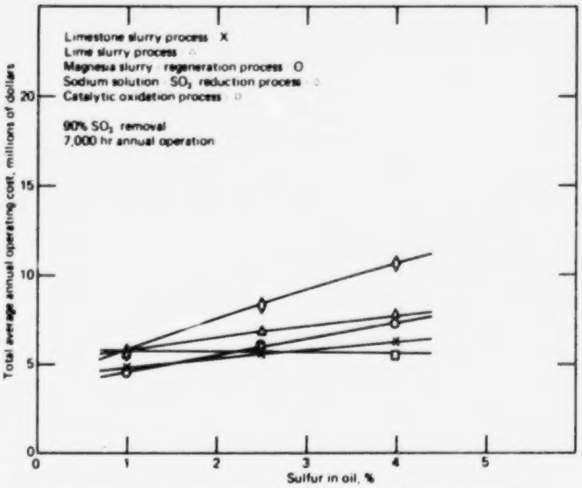


Figure 50. All processes. Effect of sulfur content of oil on total average annual operating cost: new 500-MW oil-fired units under regulated economics

scrubbing system for removal of SO_2, very little additional investment (see table 33) and operating cost are required to provide for removal of particulates.

The comparison between on-site and off-site waste disposal for the limestone and lime scrubbing processes is shown in table 58. Annual operating costs for off-site as compared to on-site disposal are 8.0% higher for the limestone slurry process, and 6.2% higher for the lime slurry process.

Detailed area-by-area base case (new and existing) operating cost breakdown analyses are shown in tables 59 through 68. In comparing the detailed operating cost breakdown analyses for the five processes, it can be seen that capital charges account for the greatest percentage of the projected operating costs for each of the five processes. The ranking of other major cost items vary depending upon the process. Table 69 shows the four major operating cost components of each process and the corresponding percent distribution of total annual operating cost attributed to each component for the base case installation. It can be seen that the costs of maintenance and energy are generally next to capital charges in magnitude.

In addition to the evaluation of effect of variables included in the case variations, the impact of changes of other selected parameters on annual operating cost was determined by sensitivity analyses. Different parameters were selected for the various processes because they do not apply uniformly.

Figures 51 and 52 show the effect of variations in annual on-stream time and sulfur content of fuel on total average annual operating costs for the limestone and sodium processes. Although not shown, projected costs for the lime and magnesia slurry processes fall in between those shown for the limestone and sodium processes. The effect of variations in annual on-stream time and sulfur content of fuel on total average annual operating costs for coal-fired power units utilizing the catalytic oxidation process are shown in figure 53. The small effect of variations in sulfur content of fuel for the Cat-Ox process is again obvious.

The effect of variations in average capital charges on the average annual operating cost for new 500-MW, 3.5% S coal-fired power units utilizing the limestone slurry process, the magnesia slurry - regeneration process, and the catalytic oxidation process are shown in figures 54 through 56. Similar results are observed for the lime and sodium processes. From these results it is obvious that the effect of varying capital charges is most pronounced on the Cat-Ox process, which requires the greatest investment.

Tables 59 through 68 presented earlier show that base case labor costs make up a larger percentage of the total projected operating costs for the magnesia slurry - regeneration process (3.40%) than for the other processes (0.71%-3.21%). Since the accuracy of labor projections may be questioned, it is worthwhile to show the effect of variations in labor requirements on annual operating costs. As an illustration, figure 57 shows the effect of doubling the estimated operating labor requirement of the magnesia slurry - regeneration process on the total annual operating cost. As suggested by the detailed operating cost distribution analysis, however, the effect of this variation is rather small.

The effect of variations in projected maintenance costs on annual operating cost is shown in figure 58 for the magnesia slurry - regeneration process. Although similar variations in maintenance projections for the other processes result in different ranges of costs, the general effect is similar.

Figures 59 and 60 show the sensitivity of annual operating costs to variations in energy cost for the sodium solution - SO_2 reduction and the catalytic oxidation processes. These processes are the most and the least sensitive to variations in energy costs, respectively, of the five processes evaluated.

It should be noted that the steam required for the SO_2 regeneration area in the sodium process (see table 65) could be reduced approximately 45% by utilizing double effect evaporators. Such a reduction would lower the overall process steam requirements approximately 33%, equivalent to a reduction in overall energy requirements of about 18%. Figure 61 shows the effect of variations in steam costs or utilization on annual operating cost for this process. Neglecting the difference in investment requirements for installing double effect evaporators, the total annual operating cost for the sodium solution - SO_2 reduction process might be reduced about 5%-6%.

Table 59. Limestone Slurry Process
Total Average Annual Operating Costs
Base Case[a] Summary – Area Contribution Analysis

	Total		Raw materials handling	Feed preparation	Particulate scrubbing	SO_2 scrubbing	Reheat	Fans	Calcium solids disposal	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	16,069,000		419,000	899,000	3,203,000	4,745,000	556,000	854,000	3,923,000	67,000	638,000	765,000			
Total capital investment, $	25,163,000		656,000	1,408,000	5,016,000	7,430,000	871,000	1,337,000	6,143,000	105,000	999,000	1,198,000			
Direct costs	Unit cost, $	Raw materials													
Delivered raw material															
Limestone	4.00/ton														
Annual quantity, tons		175,000											175,000		
Annual cost, $		700,000												700,000	9.09
Subtotal raw material cost		700,000												700,000	9.09
Conversion costs															
Operating labor and supervision	8.00/man-hr														
Annual quantity, man-hr			4,170	6,470	4,900	4,900	1,250	1,250	3,340				26,280		
Annual cost, $			33,400	51,700	39,200	39,200	10,000	10,000	26,700					210,200	2.73
Utilities															
Steam	0.70/M lb														
Annual quantity, M lb							492,800						492,800		
Annual cost, $							345,000							345,000	4.48
Process water	0.08/M gal														
Annual quantity, M gal						174,700			75,600				250,300		
Annual cost, $						14,000			6,000					20,000	0.26
Electricity	0.010/kWh														
Annual quantity, kWh			390,000	,150,000	6,440,000	22,530,000		43,080,000	700,000	230,000	220,000		78,740,000		
Annual cost, $			3,900	51,500	64,400	225,300		430,800	7,000	2,300	2,200			787,400	10.22
Maintenance (labor and material)															
Percent of direct investment			6	8	10	11	8	8	6				8		
Annual cost, $			25,000	71,000	320,000	522,000	44,500	68,000	235,000					1,285,500	16.69
Analyses	12.00/hr														
Annual quantity, hr		1,520			760	1,140			380				3,800		
Annual cost, $		18,200			9,100	13,700			4,600					45,600	0.59
Subtotal conversion costs		18,200	62,300	174,200	432,700	814,200	399,500	508,800	279,300	2,300	2,200			2,693,700	34.97
Subtotal direct costs		718,200	62,300	174,200	432,700	814,200	399,500	508,800	279,300	2,300	2,200			3,393,700	44.06
Indirect costs															
Average capital charges at 14.9% of capital investment			97,700	209,800	747,400	1,107,000	129,800	199,200	915,300	15,600	148,900	178,500		3,749,300	48.68
Overhead															
Plant, 20% of conversion costs		3,600	12,500	34,800	86,500	162,800	79,900	101,800	55,900	500	400			538,700	6.99
Administrative, 10% of operating labor			3,300	5,200	3,900	3,900	1,000	1,000	2,700					21,000	0.27
Subtotal indirect costs		3,600	113,500	249,800	837,800	1,273,800	210,700	302,000	973,900	16,100	149,300	178,500		4,309,000	55.94
Total annual operating cost		721,800	175,800	424,000	1,270,500	2,088,000	610,200	810,800	1,253,200	18,400	151,500	178,500		7,702,700	
Percent of total annual operating cost		9.37	2.28	5.50	16.49	27.11	7.92	10.53	16.27	0.24	1.97	2.32			100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	5.87	2.20	24.45	214.68

[a] Basis

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal
Remaining life of power plant, 30 yr
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh
Stack gas reheat to 175°F
Power unit on-stream time, 7,000 hr/yr
Midwest plant location, 1975 operating costs
Sulfur removed, 35,880 tons/yr, solids disposal, 206,000 tons/yr calcium solids including only hydrate water
Investment and operating cost for disposal of fly ash excluded

Table 60. Limestone Slurry Process
Total Average Annual Operating Costs
Existing Case[a] Summary   Area Contribution Analysis

	Total		Raw materials handling	Feed preparation	SO_2 scrubbing	Reheat	Fans	Calcium solids disposal	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	14,116,000		482,000	1,000,000	5,243,000	323,000	1,710,000	3,611,000	335,000	740,000	672,000			
Total capital investment, $	23,088,000		789,000	1,636,000	8,577,000	527,000	2,797,000	5,905,000	549,000	1,209,000	1,099,000			
Direct Costs		Raw materials												
Delivered raw material	Unit Cost, $													
Limestone	4.00/ton													
Annual quantity, tons		178,900										178,900		
Annual cost, $		715,600											715,600	9.07
Subtotal raw material cost		715,600											715,600	9.07
Conversion costs														
Operating labor and supervision	8.00/man hr													
Annual quantity, man hr			4,380	6,680	8,760	1,460	1,460	3,540				26,280		
Annual cost, $			35,000	53,400	70,100	11,700	11,700	28,300					210,200	2.66
Utilities														
Fuel oil (No. 6)	0.23/gal													
Annual quantity, gal						4,160,000						4,160,000		
Annual cost, $						956,800							956,800	12.12
Process water	0.08/M gal													
Annual quantity, M gal					178,600			77,300				255,900		
Annual cost, $					14,300			6,200					20,500	0.26
Electricity	0.010/kWh													
Annual quantity, kWh			400,000	5,260,000	23,030,000	20,000	35,830,000	710,000	240,000	230,000		65,720,000		
Annual cost, $			4,000	52,600	230,300	200	358,300	7,100	2,400	2,300			657,200	8.33
Maintenance (labor and supervision)														
Percent of direct investment			6	8	12	8	8	6				8		
Annual cost, $			29,000	80,000	640,300	26,000	137,000	217,000					1,129,300	14.31
Analyses	12.00/hr													
Annual quantity, hr		1,520			1,900			380				3,800		
Annual cost, $		18,200			22,800			4,600					45,600	0.58
Subtotal conversion costs		18,200	68,000	186,000	977,800	994,700	507,000	263,200	2,400	2,300			3,019,600	38.26
Subtotal direct costs		733,800	68,000	186,000	977,800	994,700	507,000	263,200	2,400	2,300			3,735,200	47.33
Indirect Costs														
Average capital charges at 15.3% of capital investment			120,700	250,300	1,312,300	80,600	427,900	903,500	84,000	185,000	168,200		3,532,500	44.75
Overhead														
Plant, 20% of conversion costs		3,600	13,600	37,200	195,600	198,900	101,400	52,600	500	500			603,900	7.65
Administrative, 10% of operating labor			3,500	5,300	7,000	1,200	1,200	2,800					21,000	0.27
Subtotal indirect costs		3,600	137,800	292,800	1,514,900	280,700	530,500	958,900	84,500	185,500	168,200		4,157,400	52.67
Total annual operating cost		737,400	205,800	478,800	2,492,700	1,275,400	1,037,500	1,222,100	86,900	187,800	168,200		7,892,600	
Percent of total annual operating cost		9.34	2.61	6.07	31.58	16.16	13.15	15.48	1.10	2.38	2.13			100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	5.88	2.26	24.51	215.17

[a] Basis:

500-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal
Remaining life of power plant, 25 yr
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh
Stack gas reheat to 175°F
Power unit on-stream time, 7,000 hr/yr
Midwest plant location, 1975 operating costs
Sulfur removed, 36,680 tons/yr; solids disposal, 210,600 tons/yr calcium solids including only hydrate water
Investment and operating cost for removal and disposal of fly ash excluded

Table 61. Lime Slurry Process
Total Average Annual Operating Costs
Base Case[a] Summary—Area Contribution Analysis

	Total		Raw materials handling	Feed preparation	Particulate-SO_2 scrubbing	SO_2 scrubbing	Reheat	Fans	Calcium solids disposal	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	14,318,000		795,000	387,000	4,017,000	3,153,000	542,000	767,000	3,356,000	67,000	552,000	682,000			
Total capital investment, $	22,422,000		1,245,000	607,000	6,291,000	4,937,000	848,000	1,201,000	5,255,000	104,000	866,000	1,068,000			
Direct Costs	Unit cost, $	Raw materials													
Delivered raw material															
Lime	22.00/ton														
Annual quantity, tons		81,200											81,200		
Annual cost, $		1,786,400												1,786,400	22.05
Subtotal raw material cost		1,786,400												1,786,400	22.05
Conversion costs															
Operating labor and supervision	8.00/man-hr														
Annual quantity, man-hr			2,290	4,390	4,900	4,900	1,250	1,250	3,340				22,320		
Annual cost, $			18,400	35,100	39,200	39,200	10,000	10,000	26,700					178,600	2.20
Utilities															
Steam	0.70/M lb														
Annual quantity, M lb							490,000						490,000		
Annual cost, $							343,000							343,000	4.23
Process water	0.08/M gal														
Annual quantity, M gal					86,500	86,500			68,900				241,900		
Annual cost, $					6,900	6,900			5,600					19,400	0.24
Electricity	0.010/kWh														
Annual quantity, kWh			220,000	340,000	14,790,000	14,790,000		43,080,000	430,000	230,000	220,000		74,100,000		
Annual cost, $			2,200	3,400	147,900	147,900		430,800	4,300	2,300	2,200			741,000	9.15
Maintenance (labor and material)															
Percent of direct investment			6	8	11	10	8	8	6				8		
Annual cost, $			48,000	31,000	442,000	315,000	44,000	62,000	203,400					1,145,400	14.14
Analyses	12.00/hr														
Annual quantity, hr		760			760	1,140			380				3,040		
Annual cost, $		9,100			9,100	13,700			4,600					36,500	0.45
Subtotal conversion costs		9,100	68,600	69,500	645,100	522,700	397,000	502,800	244,600	2,300	2,200			2,463,900	30.41
Subtotal direct costs		1,795,500	68,600	69,500	645,100	522,700	397,000	502,800	244,600	2,300	2,200			4,250,100	52.46
Indirect Costs															
Average capital charges at 14.9% of capital investment			185,500	90,400	937,400	735,600	126,400	179,000	783,000	15,500	129,000	139,100		3,340,900	41.24
Overhead															
Plant, 20% of conversion costs		1,800	13,700	13,900	129,000	104,600	79,400	100,600	48,900	500	400			492,800	6.08
Administrative, 10% of operating labor			1,900	3,500	3,900	3,900	1,000	1,000	2,700					17,900	0.22
Subtotal indirect costs		1,800	201,100	107,800	1,070,300	844,100	206,800	280,600	834,600	16,000	129,400	159,100		3,851,600	47.54
Total annual operating cost		1,797,300	269,700	177,300	1,715,400	1,366,800	603,800	783,400	1,079,200	18,300	131,600	159,100		8,101,900	
Percent of total annual operating cost		22.19	3.33	2.19	21.17	16.87	7.45	9.67	13.32	0.23	1.62	1.96			100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	6.17	2.31	25.72	225.81

[a] Basis

500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal
Remaining life of power plant, 30 yr
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh
Stack gas reheat to 175°F
Midwest plant location, 1975 operating costs
Sulfur removed, 35,880 tons/yr, solids disposal, 174,700 tons/yr calcium solids including only hydrate water
Investment and operating cost for disposal of fly ash excluded

Table 62. Lime Slurry Process
Total Average Annual Operating Costs
Existing Case[a] Annual Operating Cost Summary—Area Contribution Analysis

	Total		Raw materials handling	Feed preparation	First stage SO_2 scrubbing	Second stage SO_2 scrubbing	Reheat	Fans	Calcium solids disposal	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	15,913,000		876,000	436,000	4,565,000	3,797,000	305,000	1,143,000	3,049,000	335,000	649,000	758,000			
Total capital investment, $	26,027,000		1,433,000	714,000	7,466,000	6,211,000	498,000	1,870,000	4,986,000	549,000	1,060,000	1,240,000			
Direct Costs		Raw materials													
Delivered raw material	Unit cost, $														
Lime	22.00/ton														
Annual quantity, tons		83,000											83,000		
Annual cost, $		1,826,000												1,826,000	19.00
Subtotal raw material cost		1,826,000												1,826,000	19.00
Conversion costs															
Operating labor and supervision	8.00/man-hr														
Annual quantity, man-hr			2,290	4,390	4,900	4,900	1,250	1,250	3,340				22,320		
Annual cost, $			18,400	35,100	39,200	39,200	10,000	10,000	26,700					178,600	1.86
Utilities															
Fuel oil (No. 6)	0.23/gal														
Annual quantity, gal							4,236,000						4,236,000		
Annual cost, $							974,300							974,300	10.14
Process water	0.08/M gal														
Annual quantity, M gal					88,450	88,450			70,400				247,300		
Annual cost, $					7,100	7,100			5,600					19,800	0.21
Electricity	0.010/kWh														
Annual quantity, kWh			220,000	350,000	15,120,000	15,120,000	20,000	35,570,000	440,000	240,000	230,000		67,310,000		
Annual cost, $			2,200	3,500	151,200	151,200	200	355,700	4,400	2,400	2,300			673,100	7.00
Maintenance (labor and material)															
Percent of direct investment			6	8	11	10	8	8	6				8		
Annual cost, $			53,000	35,000	502,000	380,000	25,000	92,000	186,000					1,273,000	13.23
Analyses	12.00/hr														
Annual quantity, hr		760			760	1,140			380				3,040		
Annual cost, $		9,100			9,100	13,700			4,600					36,500	0.38
Subtotal conversion costs		9,100	73,600	73,600	708,600	591,200	1,009,500	457,700	227,300	2,400	2,300			3,155,300	32.82
Subtotal direct costs		1,835,100	73,600	73,600	708,600	591,200	1,009,500	457,700	227,300	2,400	2,300			4,981,300	51.82
Indirect Costs															
Average capital charges at 15.3% of capital investment			219,200	109,200	1,142,300	950,300	76,200	286,100	762,900	84,000	162,200	189,700		3,982,100	41.42
Overhead															
Plant, 20% of conversion costs		1,800	14,700	14,700	141,700	118,200	202,000	91,500	45,500	500	500			631,100	6.57
Administrative, 10% of operating labor			1,900	3,500	3,900	3,900	1,000	1,000	2,700					17,900	0.19
Subtotal indirect costs		1,800	235,800	127,400	1,287,900	1,072,400	279,200	378,600	811,100	84,500	162,700	189,700		4,631,100	48.18
Total annual operating cost		1,836,900	309,400	201,000	1,996,500	1,663,600	1,288,700	836,300	1,038,400	86,900	165,000	189,700		9,612,400	
Percent of total annual operating cost		19.11	3.22	2.09	20.77	17.31	13.41	8.70	10.80	0.90	1.72	1.97			100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	7.16	2.75	29.85	262.06

[a] Basis

500-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal
Remaining life of power plant, 25 yr
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh
Stack gas reheat to 175°F
Power unit on-stream time, 7,000 hr/yr
Midwest plant location, 1975 operating costs
Sulfur removed, 36,680 tons/yr, solids disposal, 178,600 tons/yr calcium solids including only hydrate water
Investment and operating cost for removal and disposal of fly ash excluded

Table 11. Magnesia Slurry—Regeneration Process
Total Average Annual Operating Costs
Base Case[a] Summary—Area Contribution Analysis

	Total		Raw materials handling	Feed preparation	Particulate scrubbing	SO_2 scrubbing	Reheat	Fans	Slurry processing	Drying	$MgSO_3$ calcination	Sulfuric acid production	Acid storage & shipping	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	16,334,000		192,000	238,000	3,966,000	2,592,000	509,000	741,000	711,000	972,000	1,108,000	3,197,000	278,000	269,000	783,000	778,000			
Total capital investment, $	26,406,000		310,000	385,000	6,412,000	4,190,000	823,000	1,198,000	1,149,000	1,571,000	1,791,000	5,168,000	450,000	435,000	1,266,000	1,258,000			
Direct Costs		Raw materials																	
Delivered raw materials	Unit cost, $																		
Lime (1st stage neutralization)	26.00/ton																		
Annual quantity, tons		134															134		
Annual cost, $		3,500																3,500	0.04
Magnesium oxide (98%)	155.00/ton																		
Annual quantity, tons		1,086															1,086		
Annual cost, $		168,300																168,300	1.83
Coke	15.00/ton																		
Annual quantity, tons		763															763		
Annual cost, $		11,400																11,400	0.12
Catalyst	1.65/liter																		
Annual quantity, liters		1,800															1,800		
Annual cost, $		3,000																3,000	0.03
Subtotal raw materials costs		186,200																186,200	2.02
Conversion costs																			
Operating labor and supervision	8.00/man-hr																		
Annual quantity, man-hr			1,440	3,720	4,450	4,450	800	800	3,720	3,840	3,840	9,680	2,460				39,200		
Annual cost, $			11,500	29,800	35,600	35,600	6,400	6,400	29,800	30,700	30,700	77,400	19,700					313,600	3.40
Utilities																			
Fuel oil (No. 6)	0.23/gal																		
Annual quantities, gal										2,558,000	2,798,000						5,356,000		
Annual cost, $										588,300	643,600							1,231,900	13.39
Steam	0.70/M lb																		
Annual quantities, M lb							440,000		89,600								529,600		
Annual cost, $							308,000		48,400[b]									356,400[b]	3.87
Heat credit	-0.60/MM Btu																		
Annual quantity, MM Btu											101,000						101,000		
Annual cost, $											(60,600)[b]							(60,600)	(0.66)
Process water	0.04/M gal																		
Annual quantity, M gal					184,800	23,700						1,999,000					2,207,500		
Annual cost, $					7,400	900						80,000						88,300	0.96
Electricity	0.010/kWh																		
Annual quantity, kWh			970,000	260,000	7,600,000	6,360,000		37,910,000	2,650,000	2,850,000	2,630,000	8,560,000	260,000	760,000	250,000		71,060,000		
Annual cost, $			9,700	2,600	76,000	63,600		379,100	26,500	28,500	26,300	85,600	2,600	7,600	2,500			710,600	7.71
Maintenance (labor and materials)																			
Percent of direct investment			5	6	10	10	8	8	7	8	8	4	4	3			7		
Annual cost, $			9,600	14,300	396,600	259,200	40,800	59,400	49,800	77,800	88,700	127,900	11,200	8,100				1,143,400	12.41
Analyses	12.00/hr																		
Annual quantity, hr		425			760	1,140			435	1,275	1,275	2,550	640				8,500		
Annual cost, $		5,100			9,100	13,700			5,200	15,300	15,300	30,600	7,700					102,000	1.11
Subtotal conversion costs		5,100	30,800	46,700	524,700	373,000	355,200	444,900	159,700	740,600	744,000	401,500	41,200	15,700	2,500			3,885,600	42.19
Subtotal direct costs		191,300	30,800	46,700	524,700	373,000	355,200	444,900	159,700	740,600	744,000	401,500	41,200	15,700	2,500			4,071,800	44.21
Indirect Costs																			
Average capital charges at 14.9% of capital investment			46,200	57,400	955,400	624,300	122,600	178,500	171,200	234,100	266,900	770,000	67,100	64,800	188,600	187,400		3,934,500	42.71
Overhead																			
Plant, 20% of conversion costs		1,000	6,200	9,300	105,000	74,600	71,100	89,000	31,900	148,100	148,800	80,300	8,200	3,100	500			777,100	8.44
Administrative and marketing, 11% of conversion costs		600	3,400	5,100	57,700	41,000	39,100	48,900	17,600	81,500	81,800	44,200	4,500	1,700	300			427,400	4.64
Subtotal indirect costs		1,600	55,800	71,800	1,118,100	739,900	232,800	316,400	220,700	463,700	497,500	894,500	79,800	69,600	189,400	187,400		5,139,000	55.79
Total annual operating cost		192,900	86,600	118,500	1,642,800	1,112,900	588,000	761,300	380,400	1,204,300	1,241,500	1,296,000	121,000	85,300	191,900	187,400		9,210,800	
Percent of total annual operating cost		2.09	0.94	1.29	17.85	12.08	6.38	8.27	4.13	13.07	13.48	14.07	1.31	0.93	2.08	2.03			100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	83.43	7.02	2.63	29.24	255.43

[a] Basis

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal; 110,400 tons/yr 100% H_2SO_4
Remaining life of power plant, 30 yr
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh
Stack gas reheat to 175°F
Power unit on-stream time, 7,000 hr/yr
Midwest plant location, 1975 operating costs
Sulfur removed, 36,060 tons/yr
Investment and operating cost for disposal of fly ash excluded

[b] Steam generated in the calcining area waste heat boiler is assessed at a unit value of $0.60/MM Btu or $0.54/M lb

Table 64. Magnesia Slurry - Regeneration Process
Total Average Annual Operating Costs
Existing Case^{a} Summary—Area Contribution Analysis

	Total		Raw materials handling	Feed preparation	SO_2 scrubbing	Reheat	Fans	Slurry processing	Cake drying	$MgSO_3$ calcination	Sulfuric acid production	Acid storage & shipping	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	15,423,000		210,000	270,000	4,469,000	305,000	1,112,000	789,000	1,065,000	1,211,000	3,608,000	329,000	454,000	867,000	734,000			
Total capital investment, $	22,056,000		354,000	456,000	7,541,000	516,000	1,876,000	1,333,000	1,796,000	2,042,000	6,089,000	556,000	766,000	1,463,000	1,238,000			
Direct Costs	Unit costs, $	Raw materials																
Delivered raw materials																		
Magnesium oxide (98%)	155.00/ton																	
Annual quantity, tons		1,110														1,110		
Annual cost, $		172,100															172,100	1.79
Coke	15.00/ton																	
Annual quantity, tons		780														780		
Annual cost, $		11,700															11,700	0.12
Catalyst	1.65/liter																	
Annual quantity, liters		1,840														1,840		
Annual cost, $		3,000															3,000	0.03
Subtotal raw materials costs		186,800															186,800	1.94
Conversion costs																		
Operating labor and supervision	8.00/man hr																	
Annual quantity, man hr			1,520	3,800	8,180	880	880	3,800	3,920	3,920	9,760	2,540				39,200		
Annual cost, $			12,200	30,400	65,400	7,000	7,000	30,400	31,400	31,400	78,100	20,300					313,600	3.26
Utilities																		
Fuel oil (No. 6)	0.23/gal																	
Annual quantity, gal						3,685,000			2,614,000	2,861,000						9,160,000		
Annual cost, $						847,600			601,200	658,000							2,106,800	21.93
Heat credit	0.60/MM Btu																	
Annual quantity, MM Btu										20,800						20,800		
Annual cost, $										(12,500)							(12,500)	(0.13)
Process water	0.04/M gal																	
Annual quantity, M gal					213,100						2,043,000					2,256,100		
Annual cost, $					8,500						81,700						90,200	0.94
Electricity	0.010/kWh																	
Annual quantity, kWh			990,000	260,000	6,500,000	20,000	21,110,000	2,710,000	2,910,000	2,690,000	8,750,000	260,000	780,000	250,000		47,230,000		
Annual cost, $			9,900	2,600	65,000	200	211,100	27,100	29,100	26,900	87,500	2,600	7,800	2,500			472,300	4.92
Maintenance (labor and material)																		
Percent of direct investment			5	6	12	8	8	7	8	8	4	4	3					
Annual cost, $			11,000	17,000	525,600	25,000	89,000	56,000	86,000	97,000	145,000	14,000	14,000				1,079,600	11.24
Analyses	12.00/hr																	
Annual quantity, hr		425			1,900			435	1,275	1,275	2,550	640				8,500		
Annual cost, $		5,100			22,800			5,200	15,300	15,300	30,600	7,700					102,000	1.06
Subtotal conversion costs		5,100	33,100	50,000	687,300	879,800	307,100	118,700	763,000	816,100	422,900	44,600	21,800	2,500			4,152,000	43.22
Subtotal direct costs		191,900	33,100	50,000	687,300	879,800	307,100	118,700	763,000	816,100	422,900	44,600	21,800	2,500			4,338,800	45.16
Indirect Costs																		
Average capital charges at 15.3% of capital investment			54,200	69,800	1,153,800	78,900	287,00	204,000	274,800	312,400	931,600	85,100	117,200	223,800	189,400		3,982,000	41.45
Overhead																		
Plant, 20% of conversion costs		1,000	6,600	10,000	137,500	176,000	61,400	23,700	152,600	163,200	84,600	8,900	4,400	500			830,400	8.64
Administrative and marketing 11% of conversion costs		600	3,600	5,500	75,500	96,800	33,800	13,100	83,900	89,800	46,500	4,900	2,400	300			456,700	4.75
Subtotal indirect costs		1,600	64,400	85,300	1,366,800	351,700	382,200	240,800	511,300	565,400	1,062,700	98,900	124,000	224,600	189,400		5,269,100	54.84
Total annual operating cost		193,500	97,500	135,300	2,054,100	1,231,500	689,300	359,500	1,274,300	1,381,500	1,485,600	143,500	145,800	227,100	189,400		9,607,900	
Percent of total annual operating cost		2.01	1.01	1.41	21.39	12.82	7.17	3.74	13.26	14.38	15.47	1.49	1.52	2.36	1.97			100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	85.10	7.16	2.75	29.84	260.66

^{a}Basis:
500-MW existing coal-fired power [illegible] SO_2 removal; [illegible] tons/yr 100% H_2SO_4.
Remaining life of power plant, [illegible]
Coal burned, 1,341,700 tons/yr, [illegible]
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 [illegible]
Midwest plant location, 1975 [illegible]
Sulfur removed, 36,860 tons/yr.
[illegible]

Table 65. Sodium Solution - SO_2 Reduction Process
Total Average Annual Operating Costs
Base Case[a] Summary—Area Contribution Analysis

	Total		Raw materials handling & preparation	Particulate scrubbing	SO_2 scrubbing	Reheat	Fans	Purge treatment	SO_2 regeneration	SO_2 reduction	Sulfur storage & shipping	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	18,861,000		225,000	3,846,000	4,269,000	539,000	889,000	1,473,000	2,717,000	2,921,000	227,000	195,000	662,000	898,000			
Total capital investment, $	30,491,000		364,000	6,218,000	6,902,000	871,000	1,417,000	2,381,000	4,393,000	4,721,000	367,000	314,000	1,071,000	1,452,000			
Direct Costs																	
Delivered raw materials	Unit cost, $	Raw materials															
Lime (1st stage neutralization)	26.00/ton																
Annual quantity, tons		134													134		
Annual cost, $		3,500														3,500	0.03
Soda ash	52.00/ton																
Annual quantity, tons		9,300													9,300		
Annual cost, $		483,600														483,600	4.17
Antioxidant	2.00/lb																
Annual quantity, lb		317,100													317,100		
Annual cost, $		634,200														634,200	5.47
Catalyst																	
Annual cost, $		12,000														12,000	0.10
Subtotal raw materials cost		1,133,300														1,133,300	9.77
Conversion costs																	
Operating labor and supervision	8.00/man-hr																
Annual quantity, man-hr			3,055	4,625	4,625	970	970	9,735	9,735	9,735	3,050				46,500		
Annual cost, $			24,400	37,000	37,000	7,800	7,800	77,900	77,900	77,900	24,300					372,000	3.21
Utilities																	
Natural gas	1.00/mcf																
Annual quantity, mcf										509,500					509,500		
Annual cost, $										509,500						509,500	4.39
Steam																	
Annual quantity, M lb	0.70/M lb					420,000		142,800	1,575,000		21,000				2,158,800		
Annual cost, $						294,000		100,000	1,102,500		11,900[b]					1,508,400[b]	13.00
Heat credit																	
Annual quantity, MM Btu	0.60/MM Btu									82,700					82,700		
Annual cost, $										(49,600)[b]						(49,600)[b]	(0.43)
Process water	0.02/M gal																
Annual quantity, M gal			8,900	169,700				326,300	9,448,500						9,953,400		
Annual cost, $			200	3,400				6,500	189,000							199,100	1.72
Electricity	0.010/kWh																
Annual quantity, kWh			450,000	7,170,000	2,230,000		43,420,000	6,500,000	11,700,000	2,070,000	170,000	230,000	250,000		74,190,000		
Annual cost, $			4,500	71,700	22,300		434,200	65,000	117,000	20,700	1,700	2,300	2,500			741,900	6.39
Maintenance (labor and material)																	
Percent of direct investment			5	10	7	8	8	6	4	4	4				6		
Annual cost, $			11,300	385,000	298,200	43,100	71,100	88,400	108,700	116,800	9,100					1,131,700	9.75
Analyses	12.00/hr																
Annual quantity, hr		640		760	1,140			2,000	1,270	2,750	600				9,160		
Annual cost, $		7,700		9,100	13,700			24,000	15,200	33,000	7,200					109,900	0.95
Subtotal conversion costs		7,700	40,400	506,200	371,200	344,900	513,100	361,800	1,610,300	708,300	54,200	2,300	2,500			4,522,900	38.98
Subtotal direct costs		1,141,000	40,400	506,200	371,200	344,900	513,100	361,800	1,610,300	708,300	54,200	2,300	2,500			5,656,200	48.75
Indirect Costs																	
Average capital charges at 14.9% of capital investment			54,200	926,500	1,028,400	129,800	214,100	354,800	654,600	703,400	54,700	46,800	159,600	216,300		4,543,200	39.16
Overhead																	
Plant, 20% of conversion costs		1,500	8,100	101,200	74,200	69,000	102,600	72,400	322,100	141,700	10,800	500	500			904,600	7.80
Administrative and marketing, 11%		900	4,400	55,700	40,800	37,900	56,400	39,800	177,100	77,900	6,000	300	300			497,500	4.29
Subtotal indirect costs		2,400	66,700	1,083,400	1,143,400	236,700	373,100	467,000	1,153,800	923,000	71,500	47,600	160,400	216,300		5,945,300	51.25
Total annual operating cost		1,143,400	107,100	1,589,600	1,514,600	581,600	886,200	828,800	2,764,100	1,631,300	125,700	49,900	162,900	216,300		11,601,300	
Percent of total annual operating cost		9.86	0.92	13.70	13.06	5.01	7.64	7.15	23.83	14.06	1.09	0.43	1.40	1.86			100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	354.79	8.84	3.31	36.83	323.34

[a] Basis

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 32,700 tons/yr sulfur
Remaining life of power plant, 30 yr
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh
Stack gas reheat to 175°F
Power unit on-stream time, 7,000 hr/yr
Midwest plant location, 1975 operating costs
Sulfur removed, 35,880 tons/yr
Investment and operating cost for disposal of fly ash excluded

[b] Steam generated in the SO_2 reduction area is assessed at a unit value of $0.60/MM Btu or $0.57/M lb

Table 66. Sodium Solution - SO_2 Reduction Process
Total Average Annual Operating Costs
Existing Case[d] Summary – Area Contribution Analysis

	Total		Raw materials handling & preparation	SO_2 scrubbing	Reheat	Fans	Purge treatment	SO_2 regeneration	SO_2 reduction	Sulfur storage & shipping	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	18,495,000		251,000	5,938,000	305,000	1,238,000	1,593,000	3,304,000	3,200,000	267,000	752,000	766,000	881,000			
Total capital investment, $	31,208,000		424,000	10,019,000	516,000	2,090,000	2,687,000	5,573,000	5,400,000	450,000	1,270,000	1,292,000	1,487,000			
Direct Costs	Unit cost, $	Raw materials														
Delivered raw materials																
Soda ash	52.00/ton															
Annual quantity, tons		9,500												9,500		
Annual cost, $		494,000													494,000	3.37
Antioxidant	2.00/lb															
Annual quantity, lb		324,100												324,100		
Annual cost, $		648,200													648,200	4.42
Catalyst																
Annual cost, $		12,300													12,300	0.08
Subtotal raw materials cost		1,154,500													1,154,500	7.87
Conversion costs																
Operating labor and supervision	8.00/man-hr															
Annual quantity, man-hr			3,175	8,395	1,095	1,095	9,855	9,855	9,855	3,175				46,500		
Annual cost, $			25,400	67,200	8,800	8,800	78,800	78,800	78,800	25,400					372,000	2.54
Utilities																
Fuel oil (No. 6)	0.23/gal															
Annual quantity, gal					4,000,000		623,000	12,944,000						17,567,000		
Annual cost, $					920,000		143,300	2,977,100							4,040,400	27.56
Natural gas	1.00/mcf															
Annual quantity, mcf									520,800					520,800		
Annual cost, $									520,800						520,800	3.55
Heat credit	-0.60/MM Btu															
Annual quantity, MM Btu							64,300							64,300		
Annual cost, $							(38,600)								(38,600)	(0.26)
Process water	0.02/M gal															
Annual quantity, M gal			9,100	173,600			333,500	9,658,200						10,174,400		
Annual cost, $			200	3,500			6,700	193,100							203,500	1.39
Electricity	0.010/kWh															
Annual quantity, kWh			460,000	2,280,000	20,000	27,130,000	6,640,000	11,960,000	2,110,000	170,000	240,000	250,000		51,260,000		
Annual cost, $			4,600	22,800	200	271,300	66,400	119,600	21,100	1,700	2,400	2,500			512,600	3.50
Maintenance (labor and material)																
Percent of direct investment			5	9	8	8	6	5	4	4	3			6		
Annual cost, $			13,000	535,000	25,000	103,000	100,000	168,000	130,000	11,700	24,000				1,109,700	7.57
Analyses	12.00/hr															
Annual quantity, hr		640		1,900			2,000	1,270	2,750	600				9,160		
Annual cost, $		7,700		22,800			24,000	15,200	33,000	7,200					109,900	0.75
Subtotal conversion costs		7,700	43,200	651,300	954,000	383,100	380,600	3,551,800	783,700	46,000	26,400	2,500			6,830,300	46.60
Subtotal direct costs		1,162,200	43,200	651,300	954,000	383,100	380,600	3,551,800	783,700	46,000	26,400	2,500			7,984,800	54.47
Indirect Costs																
Average capital charges at 15.3% of capital investment			64,900	1,532,900	78,900	319,800	411,100	852,700	826,200	68,800	194,300	197,700	227,500		4,774,800	32.58
Overhead																
Plant, 20% of conversion costs		1,500	8,600	130,300	190,800	76,600	76,100	710,400	156,800	9,200	5,300	500	–		1,366,100	9.32
Administrative and marketing		600	3,300	50,700	74,300	29,900	29,700	276,800	61,100	3,600	2,100	200	–		532,300	3.63
Subtotal indirect costs		2,100	76,800	1,713,900	344,000	426,300	516,900	1,839,900	1,044,100	81,600	201,700	198,400	227,500		6,673,200	45.53
Total annual operating cost		1,164,300	120,000	2,365,200	1,298,000	809,400	897,500	5,391,700	1,827,800	127,600	228,100	200,900	227,500		14,658,000	
Percent of total annual operating cost		7.94	0.82	16.14	8.86	5.52	6.12	36.78	12.47	0.87	1.56	1.37	1.55			100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	438.60	10.92	4.19	45.52	399.62

[a] Basis:
500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 33,420 tons/yr sulfur.
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Sulfur removed, 36,680 tons/yr.
Investment and operating cost for disposal of fly ash excluded.

Table 67. Catalytic Oxidation Process
Total Average Annual Operating Costs
Base Case[a] Summary—Area Contribution Analysis

	Total		Startup bypass ducts	Particulate removal	SO_2 conversion	Heat recovery	Fans	H_2SO_4 absorption & cooling	Acid storage & shipping	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	25,368,000		491,000	8,736,000	2,145,000	1,475,000	1,412,000	8,917,000	409,000	57,000	518,000	1,208,000			
Total capital investment, $	42,736,000		794,000	14,123,000	5,195,000	2,384,000	2,282,000	14,415,000	661,000	92,000	838,000	1,952,000			
Direct Costs															
Delivered raw material	Unit cost, $	Raw materials													
Catalyst	1.65/liter														
Annual quantity, liter		104,700											104,700		
Annual cost, $		172,800													
Subtotal raw material costs		172,800												172,800	1.95
														172,800	1.95
Conversion costs															
Operating labor and supervision	8.00/man-hr														
Annual quantity, man-hr				440	2,930	440	440	440	3,200				7,890		
Annual cost, $				3,500	23,500	3,500	3,500	3,500	25,600					63,100	0.71
Utilities															
Steam	0.70/M lb														
Annual quantity, M lb						179,000							179,000		
Annual cost, $						125,300								125,300	1.41
Heat credit	-0.60/MM Btu														
Annual quantity, MM Btu						987,000							987,000		
Annual cost, $						(592,200)								(592,200)	(6.67)
Process water	0.08/M gal														
Annual quantity, M gal								312,000					312,000		
Annual cost, $								25,000						25,000	0.28
Electricity	0.010/kWh														
Annual quantity, kWh				27,420,000	270,000	3,470,000	52,840,000	5,750,000	260,000	230,000	200,000		90,440,000		
Annual cost, $				274,200	2,700	34,700	528,400	57,500	2,600	2,300	2,000			904,400	10.19
Maintenance (labor and material)															
Percent of direct investment				3	6	3	8	5	4				4		
Annual cost, $				264,100	128,700	44,300	113,000	448,200	16,400					1,014,700	11.44
Analyses	12.00/hr														
Annual quantity, hr								3,200	800				4,000		
Annual cost, $								38,400	9,600					48,000	0.54
Subtotal conversion costs				541,800	154,900	(384,400)	644,900	572,600	54,200	2,300	2,000			1,588,300	17.90
Subtotal direct costs		172,800		541,800	154,900	(384,400)	644,900	572,600	54,200	2,300	2,000			1,761,100	19.85
Indirect Costs															
Average capital charges at 14.9% of capital investment			118,300	2,104,300	774,100	355,200	340,000	2,147,800	98,500	13,700	124,900	290,900		6,367,700	71.75
Overhead															
Plant, 20% of conversion costs				108,400	31,000	(76,900)	129,000	114,500	10,800	500	400			317,700	3.58
Administrative and marketing				136,100	33,500	(96,500)	161,900	177,700	13,600	600	500			427,400	4.82
Subtotal indirect costs			118,300	2,348,800	838,600	181,800	630,900	2,440,000	122,900	14,800	125,800	290,900		7,112,800	80.15
Total annual operating cost		172,800	118,300	2,890,600	993,500	(202,600)	1,275,800	3,012,600	177,100	17,100	127,800	290,900		8,873,900	
Percent of total annual operating cost		1.95	1.33	32.57	11.20	(2.28)	14.38	33.94	2.00	0.19	1.44	3.28			100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	80.75	6.76	2.54	28.17	247.32

[a] Basis

500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 109,900 tons/yr 100% H_2SO_4
Remaining life of power plant, 30 yr
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs
Sulfur removed, 35,880 tons/yr
Investment and operating cost for disposal of fly ash excluded.

Table 68. Catalytic Oxidation Process
Total Average Annual Operating Costs
Existing Case[a] Summary—Area Contribution Analysis

	Total		Startup bypass ducts	Particulate removal	SO_2 conversion	Reheat	Fans	H_2SO_4 absorption & cooling	Acid storage & shipping	Utilities	Services	Construction facilities	Total annual quantities	Total annual dollars	Percent of total annual operating cost
Direct capital investment, $	21,419,000		304,000	4,260,000	1,983,000	3,258,000	2,133,000	6,840,000	481,000	527,000	613,000	1,020,000			
Total capital investment, $	37,907,000		511,000	7,188,000	5,113,000	5,498,000	3,599,000	11,542,000	812,000	888,000	1,035,000	1,721,000			
Direct Costs		Raw materials													
Delivered raw material	Unit cost, $														
Catalyst	1.65/liter														
Annual quantity, liters		107,000											107,000		
Annual cost, $		176,600												176,600	1.42
Subtotal raw material costs		176,600												176,600	1.42
Conversion costs															
Operating labor and supervision	8.00/man-hr														
Annual quantity, man-hr				440	2,930	440	440	440	3,200				7,890		
Annual cost, $				3,500	23,500	3,500	3,500	3,500	25,600					63,100	0.51
Utilities															
Fuel oil (No. 2)	0.30/gal														
Annual quantity, gal						10,330,000							10,330,000		
Annual cost, $						3,099,000								3,099,000	24.99
Process water	0.02/M gal														
Annual quantity, M gal								7,961,000					7,961,000		
Annual cost, $								159,200						159,200	1.28
Electricity	0.010/kWh														
Annual quantity, kWh				3,500,000	270,000	140,000	66,800,000	3,180,000	260,000	240,000	210,000		74,600,000		
Annual cost, $				35,000	2,700	1,400	668,000	31,800	2,600	2,400	2,100			746,000	6.02
Maintenance (labor and material)															
Percent of direct investment				2	6	6	8	4	4				4		
Annual cost, $				85,200	116,000	195,500	170,600	270,300	19,200					856,800	6.91
Analyses	12.00/hr														
Annual quantity, hr								3,200	800				4,000		
Annual cost, $								38,400	9,600					48,000	0.39
Subtotal conversion costs				123,700	142,200	3,299,400	842,100	503,200	57,000	2,400	2,100			4,972,100	40.10
Subtotal direct costs		176,600		123,700	142,200	3,299,400	842,100	503,200	57,000	2,400	2,100			5,148,700	41.52
Indirect Costs															
Average capital charges at 15.3% of capital investment			78,300	1,099,800	782,300	841,200	550,600	1,765,900	124,200	135,800	158,400	263,300		5,799,800	46.78
Overhead															
Plant, 20% of conversion costs				24,700	28,400	659,900	168,400	100,700	11,400	500	400			994,400	8.02
Administrative and marketing				11,100	11,200	296,200	75,600	57,100	5,100	200	200			456,700	3.68
Subtotal indirect costs			78,300	1,135,600	821,900	1,797,300	794,600	1,923,700	140,700	136,500	159,000	263,300		7,250,900	58.48
Total annual operating cost		176,600	78,300	1,259,300	964,100	5,096,700	1,636,700	2,426,900	197,700	138,900	161,100	263,300		12,399,600	
Percent of total annual operating cost		1.43	0.63	10.16	7.78	41.10	13.20	19.57	1.59	1.12	1.30	2.12			100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent total unit operating cost	110.41	9.24	3.54	38.51	338.05

[a] Basis
500 MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, 112,300 tons/yr 100% H_2SO_4
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr; 9,200 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Sulfur removed, 36,680 tons/yr.
Investment and operating cost for disposal of fly ash excluded.

Table 69. Major Operating Cost Components Included in the Base Case Total Annual Operating Cost

Process	Major operating cost components (percent of total annual operating cost)			
	1	2	3	4
Limestone slurry	Capital charges (48.68)	Maintenance (16.69)	Electricity (10.22)	Limestone (9.09)
Lime slurry	Capital charges (41.24)	Lime (22.05)	Maintenance (14.14)	Electricity (9.15)
Magnesia slurry - regeneration	Capital charges (42.71)	Fuel oil (13.39)	Maintenance (12.41)	Plant overhead (8.44)
Sodium solution - SO_2 reduction	Capital charges (39.16)	Steam (13.00)	Maintenance (9.75)	Plant overhead (7.80)
Catalytic oxidation	Capital charges (71.75)	Maintenance (11.44)	Electricity (10.19)	Administrative and marketing overhead (4.82)

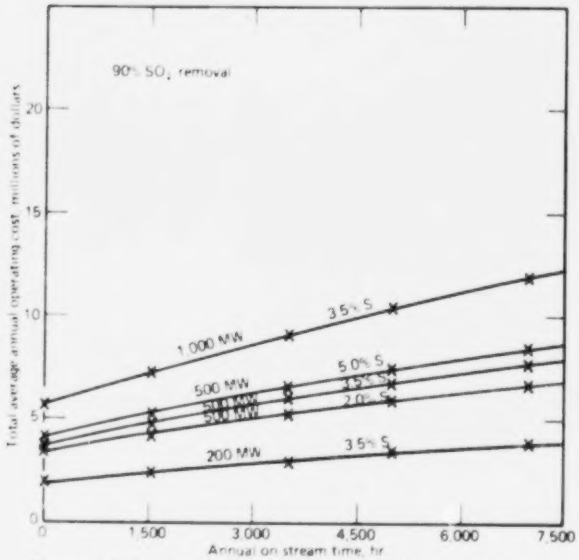


Figure 51. Limestone slurry process. Effect of annual on-stream time on total average annual operating cost: new coal-fired units under regulated economics

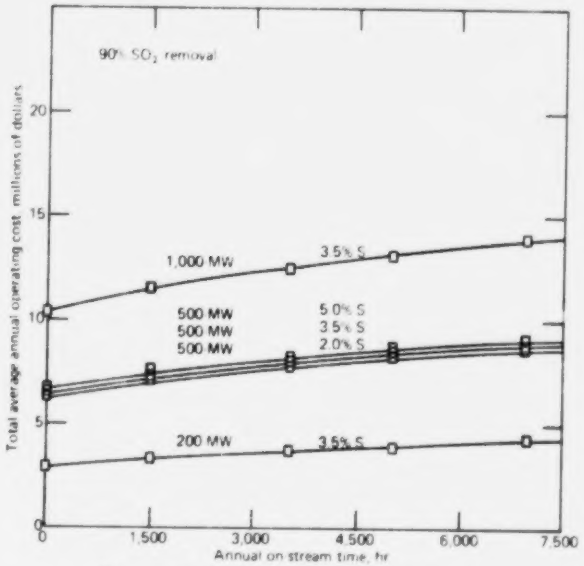


Figure 53. Catalytic oxidation process. Effect of annual on-stream time on total average annual operating cost: new coal-fired units under regulated economics

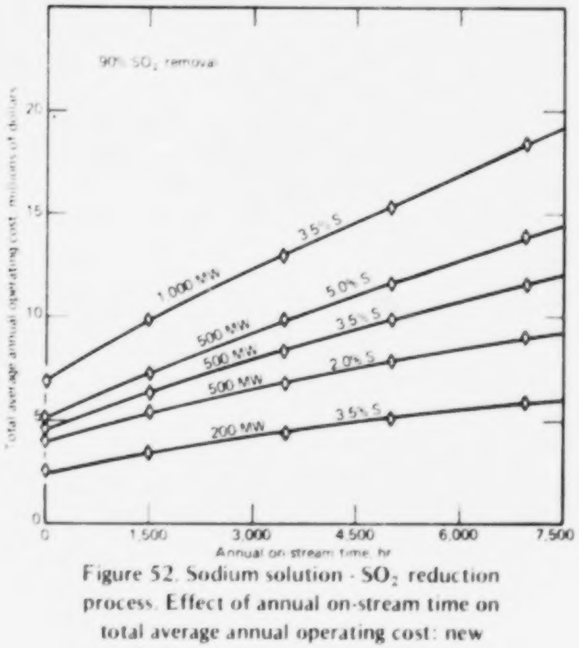


Figure 52. Sodium solution - SO_2 reduction process. Effect of annual on-stream time on total average annual operating cost: new coal-fired units under regulated economics

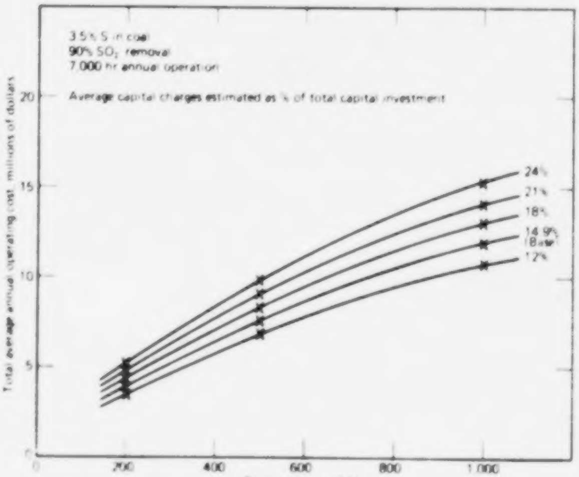


Figure 54. Limestone slurry process. Effect of variations in capital charges on total average annual operating cost: new coal-fired units under regulated economics

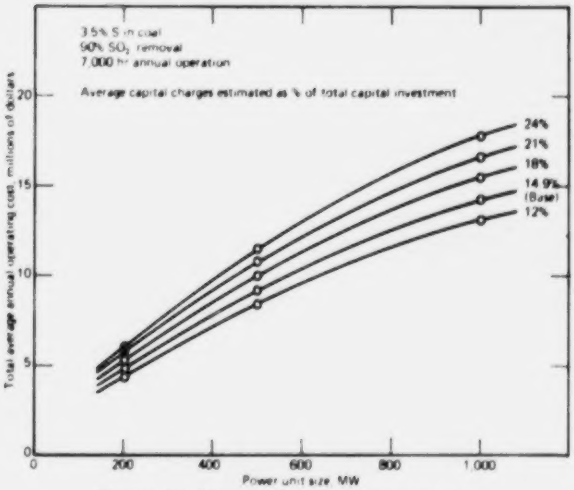


Figure 55. Magnesia slurry - regeneration process. Effect of variations in capital charges on total average annual operating cost: new coal-fired units under regulated economics

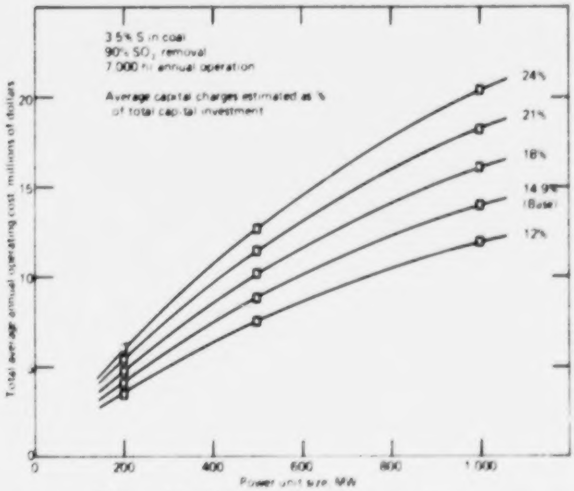


Figure 56. Catalytic oxidation process. Effect of variations in capital charges on total average annual operating cost: new coal-fired units under regulated economics

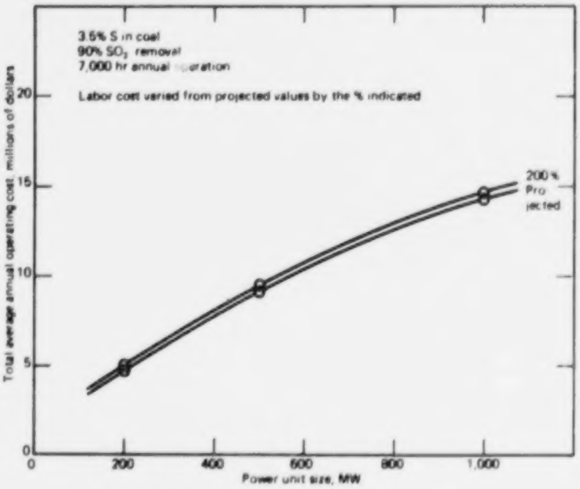


Figure 57. Magnesia slurry - regeneration process. Effect of variations in labor cost on total average annual operating cost: new coal-fired units under regulated economics

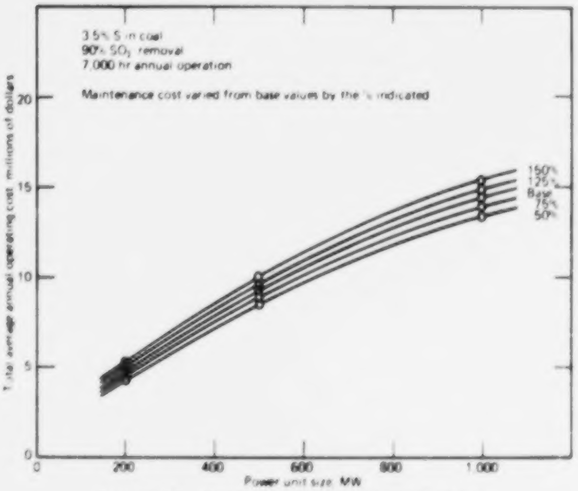


Figure 58. Magnesia slurry - regeneration process. Effect of variations in maintenance cost on total average annual operating cost: new coal-fired units under regulated economics

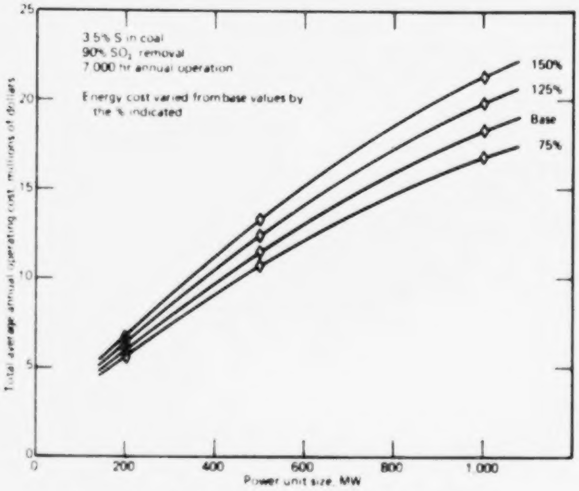


Figure 59. Sodium solution - SO_2 reduction process. Effect of variations in energy cost on total average annual operating cost: new coal-fired units under regulated economics

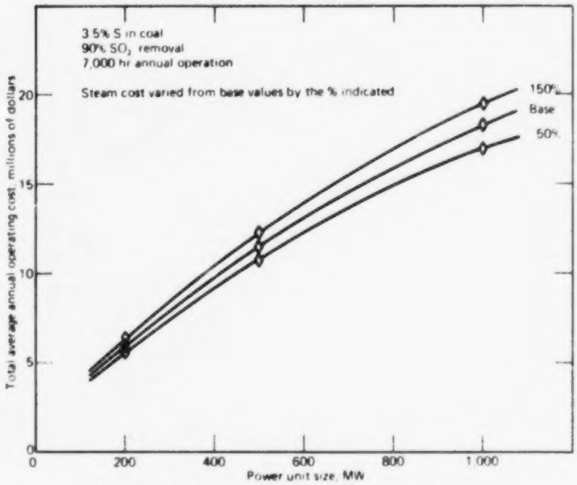


Figure 61. Sodium solution - SO_2 reduction process. Effect of variations in steam cost on total average annual operating cost: new coal-fired units under regulated economics

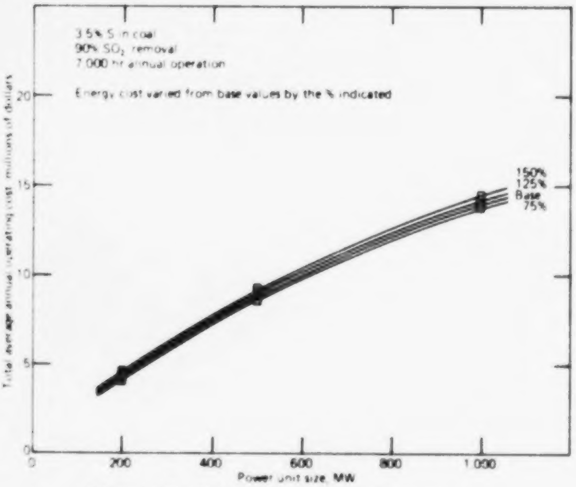


Figure 60. Catalytic oxidation process. Effect of variations in energy cost on total average annual operating cost: new coal-fired units under regulated economics

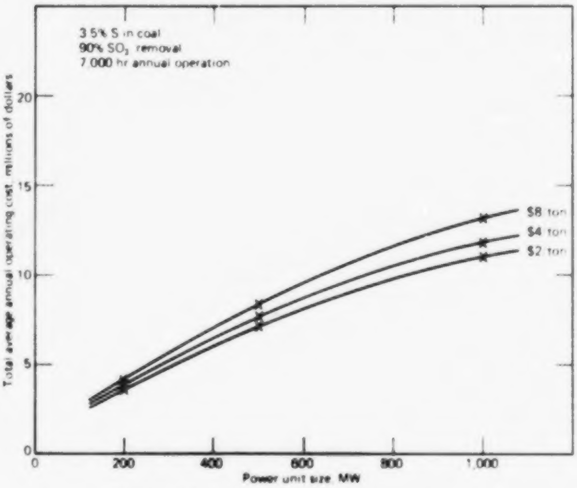


Figure 62. Limestone slurry process. Effect of variations in limestone price on total average annual operating cost: new coal-fired units under regulated economics

The sensitivity of the limestone and lime slurry process annual operating costs to variations in raw material price, and solid disposal method and costs are indicated in figures 62 through 64. As can be seen in the tabulated results, presented in table 58, operating costs for limestone and lime scrubbing processes utilizing off-site disposal are higher than those for processes utilizing low-cost on-site disposal. A wide range of overall costs could be encountered.

Figure 65 indicates the sensitivity of projected annual operating costs of the magnesia slurry - regeneration process to magnesia losses encountered during drying, regeneration and cycling of the absorbent.

The effect of antioxidant utilization on the annual operating cost of the sodium scrubbing - SO_2 reduction to S process, corresponding to new 3.5% S coal-fired units is shown in figure 66. This figure compares the operating costs for sodium systems designed for no antioxidant

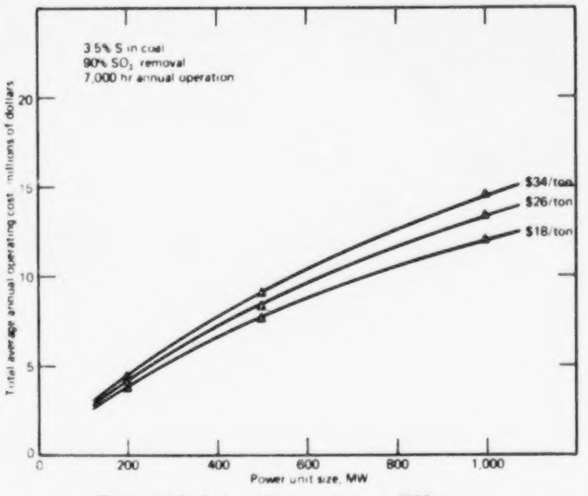


Figure 63. Lime slurry process. Effect of variations in lime price on total average annual operating cost: new coal-fired units under regulated economics

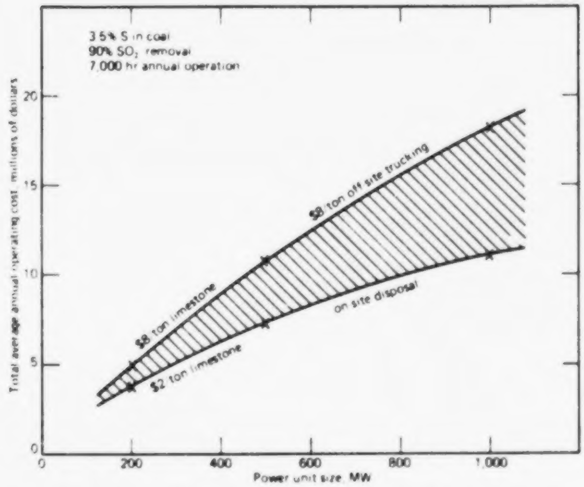


Figure 64. Limestone slurry process. Effect of variations in limestone price and in disposal method on total average annual operating cost: new coal-fired units under regulated economics

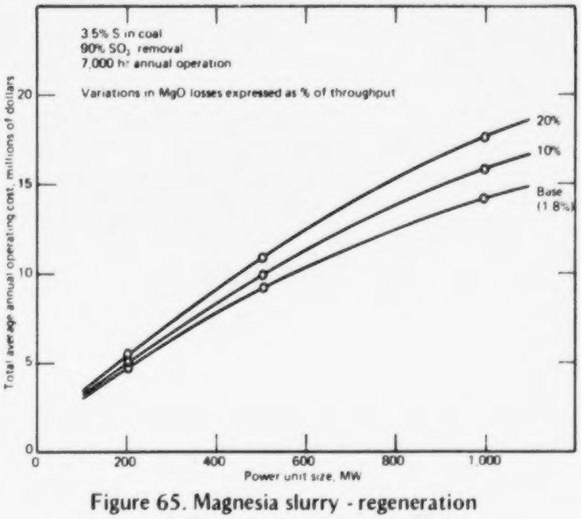


Figure 65. Magnesia slurry - regeneration process. Effect of variations in MgO losses on total average annual operating cost: new coal-fired units under regulated economics

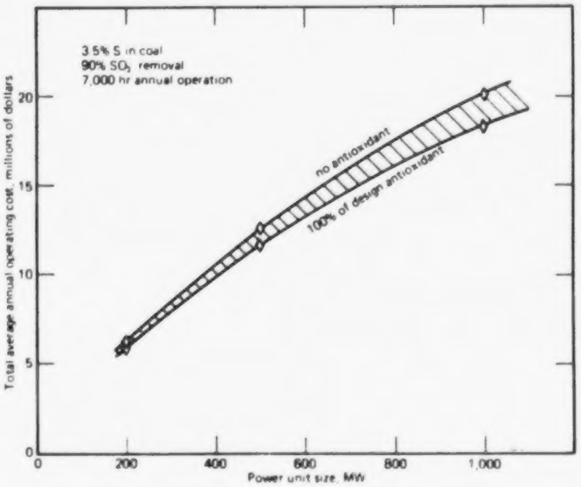


Figure 66. Sodium solution - SO_2 reduction process. Effect of antioxidant use on total average annual operating cost: new coal-fired units under regulated economics

utilization with costs for systems designed for the amount recommended by the process developer, considering the overall relationship between antioxidant utilization, sulfite oxidation, and makeup sodium carbonate requirements.

Figure 67 shows the effect of catalyst losses on the annual operating cost for the catalytic oxidation process. The lower curve, indicating 10% catalyst losses per year, corresponds to the expected costs for new coal-fired power units which have 99.9% efficient electrostatic precipitators (outlet fly ash loading of 0.005 gr/scf), and require cleaning of the catalyst only four times per year. If, however, the electrostatic precipitators are not capable of operating at the high efficiency desired, additional cleanings would be required. The middle and upper curves indicate the effect of additional cleanings and corresponding catalyst losses on the projected annual operating costs.

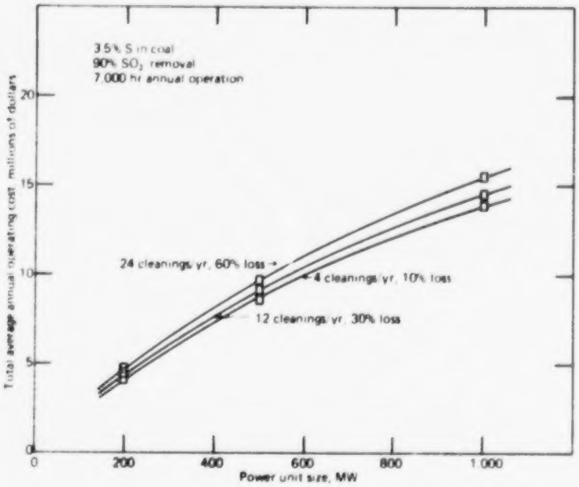


Figure 67. Catalytic oxidation process. Effect of variations in number of cleanings (and resulting catalyst loss) on total average annual operating cost: new coal-fired units under regulated economics

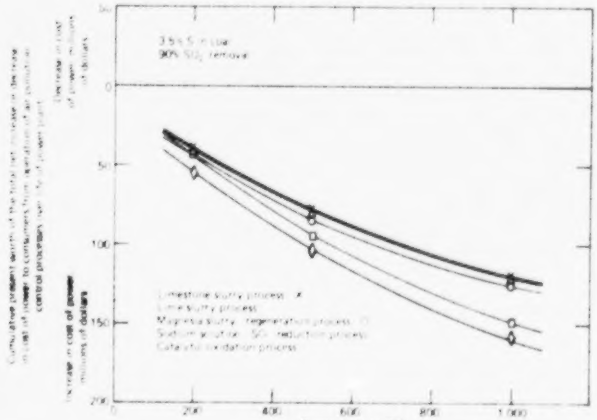


Figure 68. All processes. Effect of power unit size on cumulative present worth of total increase or decrease in cost of power to consumers: new coal-fired units under regulated economics

Lifetime Operating Cost

Along with the investment and annual operating cost summary tables given in Appendix B, computer projections of the detailed year-to-year operating cost and sales revenue analyses for the base case and 16 variations for each of the five processes are presented. These projections are prepared on a regulated economics basis as discussed in the procedure and correspond to the 30-year declining operating profile of the unit established in the power plant premises. Annual capital charges are based on the

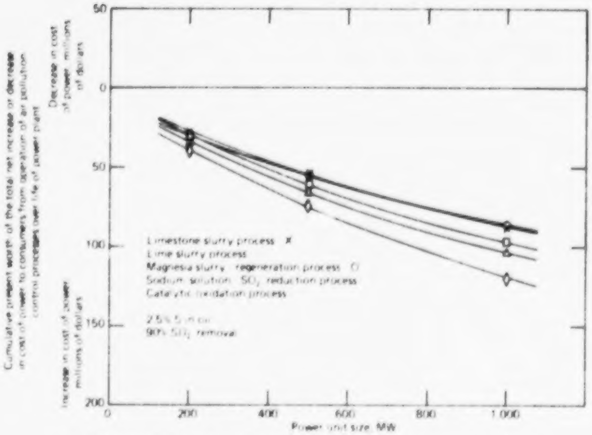


Figure 69. All processes. Effect of power unit size on cumulative present worth of total increase or decrease in cost of power to consumers: new oil-fired units under regulated economics

undepreciated investment. The overall net increase or decrease in cost of power is shown for each year, considering the declining annual operating cost and the net sales revenue resulting from sale of marketable byproducts. Lifetime costs, both total and discounted (at the regulated cost of money—10% for this study) are displayed, and equivalent unit operating cost are shown. Summarized results of the lifetime operating cost projections for the five processes are presented in tables 70 through 74. Table 75 shows the cumulative lifetime credits, both actual and discounted, for the magnesia, sodium, and Cat-Ox processes which are included in the lifetime cost projections.

The total discounted lifetime operating costs for the five processes are presented graphically in figures 68 and 69 for new coal- and oil-fired power units. The effect of power unit size on equivalent levelized unit operating costs for new coal- and oil-fired power units are presented in figures 70 and 71. These unit cost results show trends somewhat similar to those given in the annual operating cost estimates; however, the magnitude of the costs are higher. These higher costs are the result of the declining operating profile of the power plant. In comparison with the ranking of average annual unit operating costs given earlier, the relative lifetime costs may be shifted slightly since product revenue is reflected where applicable and since declining balance capital charges in conjunction with discounted process costs tend to penalize processes requiring a high capital investment.

The effect of power unit size on levelized unit operating costs for existing coal-fired power units is given in figure 72.

Figures 73 and 74 show the effect of sulfur content of fuel on levelized unit operating costs for new 500-MW coal-

Table 70. Limestone Slurry Process
Actual and Discounted Cumulative Total and Unit Increase (Decrease) in Cost of Power over the Life of the Power Unit[a]

Case	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit operating cost				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost[c]			
		Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton of sulfur removed		Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton of sulfur removed
Coal-fired power unit										
90% SO_2 removal; on-site solids disposal										
200 MW N 3.5% S 30 yr	99,119,400	10.14	3.89	42.25	371.23	40,142,800	9.5[illegible]	3.66	39.76	348.76
200 MW E 3.5% S 20 yr	57,203,400	12.57	4.97	52.36	461.32	29,067,800	11.94	4.73	49.76	437.77
500 MW E 3.5% S 25 yr	153,722,200	8.67	3.32	36.13	316.95	70,550,000	8.07	3.09	33.61	295.06
500 MW N 2.0% S 30 yr	170,746,900	7.14	2.68	29.76	457.15	69,314,200	6.74	2.53	28.07	431.33
500 MW N 3.5% S 30 yr	193,110,500	8.08	3.03	33.66	295.50	78,439,900	7.63	2.86	31.77	278.85
500 MW N 5.0% S 30 yr	212,604,300	8.89	3.33	37.06	227.63	86,426,800	8.40	3.15	35.01	214.99
1,000 MW E 3.5% S 25 yr	242,836,600	7.00	2.63	29.17	255.89	111,985,400	6.55	2.45	27.27	239.29
1,000 MW N 3.5% S 30 yr	294,508,400	6.37	2.31	26.55	232.91	120,015,500	6.03	2.19	25.14	220.62
80% SO_2 removal; on-site solids disposal										
500 MW N 3.5% S 30 yr	185,360,800	7.75	2.91	32.31	319.31	75,259,300	7.32	2.74	30.48	301.04
90% SO_2 removal; off-site solids disposal										
500 MW N 3.5% S 30 yr	195,872,700	8.19	3.07	34.14	299.73	80,426,200	7.82	2.93	32.57	285.91
90% SO_2 removal; on-site solids disposal (existing unit requiring particulate scrubber)										
500 MW E 3.5% S 25 yr	190,383,800	10.74	4.12	44.74	392.54	87,143,300	9.96	3.82	41.52	364.46
Oil-fired power unit										
90% SO_2 removal; on-site solids disposal										
200 MW N 2.5% S 30 yr	69,607,000	1.86	2.73	29.67	488.47	28,281,000	1.75	2.58	28.01	462.11
500 MW N 1.0% S 30 yr	113,517,500	1.24	1.78	19.79	813.75	46,404,800	1.18	1.69	18.80	770.84
500 MW N 2.5% S 30 yr	133,973,500	1.46	2.10	23.35	384.43	54,743,900	1.39	2.00	22.17	365.45
500 MW N 4.0% S 30 yr	151,255,000	1.65	2.37	26.36	271.07	61,808,400	1.57	2.25	25.03	257.64
500 MW E 2.5% S 25 yr	126,916,800	1.87	2.74	29.83	490.03	58,358,800	1.74	2.56	27.81	457.00
1,000 MW N 2.5% S 30 yr	212,367,000	1.20	1.67	19.15	315.32	87,171,700	1.14	1.59	18.26	300.70

[a] Basis:

Stack gas reheat to 175°F.
Over previously defined power unit operating profile. 30 yr life; 7,000 hr–10 yr, 5,000 hr–5 yr, 3,500 hr–5 yr, 1,500 hr–10 yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.
Limestone raw material cost, $4/ton.
Trucking and off-site costs for calcium solids disposal, $4/ton.
Constant labor cost assumed over life of project.

[b] Discounted at 10% to initial year.

[c] Equivalent to discounted process cost over life of power units.

Table 71. Lime Slurry Process
Actual and Discounted Cumulative Total and Unit Increase (Decrease) in Cost of Power over the Life of the Power Unit[a]

Case	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit operating cost				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost[c]			
		Dollars/ton (bbl) of coal (oil) burned	Mills/ kWh	Cents/ million Btu heat input	Dollars/ ton of sulfur removed		Dollars/ton (bbl) of coal (oil) burned	Mills/ kWh	Cents/ million Btu heat input	Dollars/ ton of sulfur removed
Coal-fired power unit										
90% SO_2 removal; on-site solids disposal										
200 MW N 3.5% S 30 yr	100,776,300	10.31	3.95	42.96	377.44	41,112,500	9.77	3.75	40.72	357.19
200 MW E 3.5% S 20 yr	68,615,500	15.08	5.97	62.81	553.35	34,979,000	14.37	5.69	59.88	526.79
500 MW E 3.5% S 25 yr	182,422,100	10.29	3.94	42.87	376.13	84,117,600	9.62	3.69	40.08	351.81
500 MW N 2.0% S 30 yr	168,298,800	7.04	2.64	29.33	450.60	68,709,000	6.68	2.50	27.83	427.56
500 MW N 3.5% S 30 yr	194,580,100	8.14	3.05	33.91	297.75	79,593,300	7.74	2.90	32.24	282.95
500 MW N 5.0% S 30 yr	217,913,400	9.12	3.42	37.98	233.31	89,293,900	8.68	3.25	36.17	222.12
1,000 MW E 3.5% S 25 yr	282,501,000	8.14	3.05	33.93	297.68	130,977,300	7.66	2.87	31.90	279.87
1,000 MW N 3.5% S 30 yr	296,557,800	6.42	2.33	26.73	234.53	121,789,900	6.12	2.22	25.51	223.88
80% SO_2 removal; on-site solids disposal										
500 MW N 3.5% S 30 yr	187,497,300	7.84	2.94	32.68	322.99	76,687,900	7.45	2.80	31.06	306.75
90% SO_2 removal; off-site solids disposal										
500 MW N 3.5% S 30 yr	195,982,800	8.20	3.07	34.16	299.90	80,903,300	7.86	2.95	32.77	287.61
90% SO_2 removal; on-site solids disposal (existing unit requiring particulate scrubber)										
500 MW E 3.5% S 25 yr	184,085,400	10.38	3.98	43.26	379.56	84,924,200	9.71	3.72	40.46	355.18
Oil-fired power unit										
90% SO_2 removal; on-site solids disposal										
200 MW N 2.5% S 30 yr	82,415,500	2.20	3.23	35.13	578.35	33,612,500	2.08	3.06	33.30	549.22
500 MW N 1.0% S 30 yr	138,130,800	1.51	2.17	24.08	990.18	56,505,800	1.43	2.06	22.89	938.63
500 MW N 2.5% S 30 yr	162,810,600	1.78	2.55	28.38	467.18	66,727,200	1.69	2.43	27.03	445.44
500 MW N 4.0% S 30 yr	182,607,400	1.99	2.86	31.83	327.25	74,929,500	1.90	2.73	30.35	312.34
500 MW E 2.5% S 25 yr	152,088,300	2.24	3.29	35.74	587.21	70,126,200	2.09	3.07	33.41	549.15
1,000 MW N 2.5% S 30 yr	251,141,900	1.42	1.97	22.64	372.89	103,411,900	1.36	1.88	21.66	356.72

[a] Basis:
Stack gas reheat to 175°F.
Over previously defined power unit operating profile. 30 yr life; 7,000 hr–10 yr, 5,000 hr–5 yr, 3,500 hr–5 yr, 1,500 hr–10 yr.
Midwest plant location, 1975 operating costs.
Investment and operating cost for disposal of fly ash excluded.
Trucking and off-site costs for calcium solids disposal, $4/ton.
Constant labor cost assumed over life of project.

[b] Discounted at 10% to initial year.

[c] Equivalent to discounted process cost over life of power units.

Table 72. Magnesia Slurry - Regeneration Process Actual and Discounted Cumulative Total and Unit Increase (Decrease) in Cost of Power over the Life of the Power Unit[a]

Case	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit operating cost				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost[c]			
		Dollars/ton (bbl) of coal (oil) burned	Mills/ kWh	Cents/ million Btu heat input	Dollars/ ton of sulfur removed		Dollars/ton (bbl) of coal (oil) burned	Mills/ kWh	Cents/ million Btu heat input	Dollars/ ton of sulfur removed
Coal-fired power unit										
90% SO_2 removal										
200 MW N 3.5% S 30 yr	110,802,200	11.34	4.35	47.23	412.67	44,860,300	10.66	4.09	44.44	389.07
200 MW E 3.5% S 20 yr	71,186,500	15.64	6.19	65.16	567.22	36,106,200	14.84	5.87	61.81	538.90
500 MW E 3.5% S 25 yr	170,821,300	9.64	3.69	40.15	350.76	78,292,200	8.95	3.43	37.30	325.81
500 MW N 2.0% S 30 yr	176,081,200	7.37	2.76	30.69	469.55	71,503,600	6.95	2.61	28.96	443.02
500 MW N 3.5% S 30 yr	207,239,000	8.67	3.25	36.12	315.43	84,249,500	8.19	3.07	34.12	297.81
500 MW N 5.0% S 30 yr	235,017,500	9.83	3.69	40.96	250.55	95,621,900	9.30	3.49	38.73	236.86
1,000 MW E 3.5% S 25 yr	262,956,000	7.58	2.84	31.59	275.78	121,156,200	7.08	2.66	29.50	257.72
1,000 MW N 3.5% S 30 yr	310,696,300	6.72	2.44	28.01	244.74	126,808,000	6.38	2.31	26.57	232.12
80% SO_2 removal										
500 MW N 3.5% S 30 yr	199,642,700	8.35	3.13	34.80	341.56	81,119,800	7.89	2.96	32.86	322.54
90% SO_2 removal (existing unit requiring particulate scrubber)										
500 MW E 3.5% S 25 yr	205,075,200	11.57	4.43	48.20	421.10	93,875,800	10.73	4.12	44.73	390.66
Oil-fired power unit										
90% SO_2 removal										
200 MW N 2.5% S 30 yr	74,295,900	1.98	2.91	31.67	517.74	30,089,900	1.87	2.74	29.81	486.89
500 MW N 1.0% S 30 yr	108,158,200	1.18	1.70	18.85	775.33	44,030,300	1.12	1.61	17.83	731.40
500 MW N 2.5% S 30 yr	136,607,500	1.49	2.14	23.81	390.87	55,673,400	1.41	2.03	22.55	370.17
500 MW N 4.0% S 30 yr	160,718,300	1.75	2.52	28.01	286.49	65,572,800	1.66	2.39	26.56	271.64
500 MW E 2.5% S 25 yr	133,978,500	1.97	2.90	31.49	516.29	61,393,300	1.83	2.69	29.25	479.26
1,000 MW N 2.5% S 30 yr	209,805,800	1.18	1.65	18.91	309.45	85,962,400	1.13	1.57	18.01	294.80

[a] Basis:

Stack gas reheat to 175°F.

Over previously defined power unit operating profile. 30 yr life; 7,000 hr–10 yr, 5,000 hr–5 yr, 3,500 hr–5 yr, 1,500–10 yr.

Midwest plant location, 1975 operating costs.

Investment and operating cost for disposal of fly ash excluded.

Revenue, $8/ton, 100% H_2SO_4.

Constant labor cost assumed over life of project.

[b] Discounted at 10% to initial year.

[c] Equivalent to discounted process cost over life of power units.

Table 73. Sodium Solution - SO_2 Reduction Process Actual and Discounted Cumulative Total and Unit Increase (Decrease) in Cost of Power over the Life of the Power Unit[a]

Case	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit operating cost				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost[c]			
Coal-fired power unit		Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton of sulfur removed		Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton of sulfur removed
90% SO_2 removal										
200 MW N 3.5% S 30 yr	135,200,000	13.83	5.30	57.63	506.37	55,045,000	13.09	5.02	54.53	478.24
200 MW E 3.5% S 20 yr	95,051,600	20.88	8.27	87.00	766.55	48,568,300	19.96	7.90	83.14	731.45
500 MW E 3.5% S 25 yr	**245,102,700**	**13.82**	**5.30**	**57.60**	**505.37**	**113,985,500**	**13.03**	**5.00**	**54.31**	**476.73**
500 MW N 2.0% S 30 yr	210,050,100	8.79	3.29	36.61	562.38	85,60[illegible],900	8.32	3.12	34.67	532.70
500 MW N 3.5% S 30 yr	255,114,300	10.67	4.00	44.46	390.38	104,292,300	10.14	3.80	42.24	370.75
500 MW N 5.0% S 30 yr	296,905,800	12.42	4.66	51.75	317.89	121,660,300	11.83	4.43	49.28	302.64
1,000 MW E 3.5% S 25 yr	402,645,600	11.61	4.35	48.37	424.28	188,464,400	11.01	4.13	45.90	402.70
1,000 MW N 3.5% S 30 yr	390,806,900	8.46	3.07	35.23	309.06	160,375,200	8.06	2.92	33.60	294.81
80% SO_2 removal										
500 MW N 3.5% S 30 yr	240,560,300	10.06	3.77	41.93	414.40	98,245,000	9.55	3.58	39.79	392.98
90% SO_2 removal (existing unit requiring particulate scrubber)										
500 MW E 3.5% S 25 yr	281,830,300	15.90	6.09	66.24	581.09	130,713,900	14.95	5.73	62.28	546.69
Oil-fired power unit										
90% SO_2 removal										
200 MW N 2.5% S 30 yr	95,903,600	2.56	3.76	40.88	673.01	39,147,900	2.43	3.57	38.78	639.67
500 MW N 1.0% S 30 yr	134,582,300	1.47	2.11	23.46	964.75	55,025,400	1.39	2.01	22.29	914.04
500 MW N 2.5% S 30 yr	180,606,100	1.97	2.83	31.48	518.24	74,204,600	1.88	2.70	30.06	495.36
500 MW N 4.0% S 30 yr	222,853,600	2.43	3.50	38.84	399.38	91,887,900	2.33	3.35	37.22	383.03
500 MW E 2.5% S 25 yr	178,718,300	2.63	3.86	42.00	690.03	82,852,700	2.47	3.63	39.48	648.81
1,000 MW N 2.5% S 30 yr	286,613,900	1.62	2.25	25.84	425.56	118,705,700	1.56	2.16	24.87	409.47

[a] Basis:

Stack gas reheat to 175°F.

Over previously defined power unit operating profile, 30 yr life: 7,000 hr 10 yr, 5,000 hr 5 yr, 3,500 hr 5 yr, 1,500 hr 10 yr.

Midwest plant location, 1975 operating cost.

Investment and operating cost for disposal of fly ash excluded.

Revenue, \$25/ton, sulfur; \$20/ton, Na_2SO_4.

Constant labor cost assumed over life of project.

[b] Discounted at 10% to initial year.

[c] Equivalent to discounted process cost over life of power units.

Table 74. Catalytic Oxidation Process
Actual and Discounted Cumulative Total and Unit Increase (Decrease) in Cost of Power over the Life of the Power Unit[a]

Case	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit operating cost				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost[c]			
		Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton of sulfur removed		Dollars/ton (bbl) of coal (oil) burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton of sulfur removed
Coal-fired power unit										
90% SO_2 removal										
200 MW N 3.5% S 30 yr	111,370,000	11.39	4.37	47.47	417.12	44,823,500	10.66	4.08	44.40	389.43
200 MW E 3.5% S 20 yr	83,064,800	18.25	7.22	76.03	669.88	42,423,000	17.43	6.90	72.62	638.90
500 MW E 3.5% S 25 yr	231,056,400	13.03	5.00	54.30	476.40	106,607,800	12.19	4.67	50.79	445.87
500 MW N 2.0% S 30 yr	237,377,500	9.93	3.72	41.37	635.55	95,780,300	9.31	3.49	38.79	596.02
500 MW N 3.5% S 30 yr	234,219,400	9.80	3.67	40.82	358.41	94,320,900	9.17	3.44	38.20	335.30
500 MW N 5.0% S 30 yr	239,951,400	9.66	3.62	40.25	247.27	92,805,300	9.02	3.38	37.59	230.86
1,000 MW E 3.5% S 25 yr	390,958,500	11.27	4.23	46.96	411.97	181,012,700	10.58	3.97	44.08	386.78
1,000 MW N 3.5% S 30 yr	367,669,100	7.96	2.88	33.15	290.76	148,117,600	7.45	2.70	31.03	272.28
90% SO_2 removal (existing unit without existing particulate collection facilities)										
500 MW E 3.5% S 25 yr	258,758,900	14.60	5.59	60.81	533.52	119,124,800	13.62	5.22	56.76	498.22
Oil-fired power unit										
90% SO_2 removal										
200 MW N 2.5% S 30 yr	73,836,300	1.97	2.90	31.47	518.15	29,653,800	1.84	2.70	29.37	484.54
500 MW N 1.0% S 30 yr	157,587,800	1.72	2.47	27.47	1,129.66	63,574,000	1.61	2.32	25.75	1,056.05
500 MW N 2.5% S 30 yr	153,253,600	1.67	2.40	26.71	439.75	61,591,500	1.56	2.25	24.95	411.16
500 MW N 4.0% S 30 yr	148,200,000	1.62	2.32	25.83	265.59	59,249,500	1.50	2.16	24.00	246.98
500 MW E 2.5% S 25 yr	208,160,100	3.06	4.50	48.92	803.71	96,305,200	2.87	4.22	45.89	754.15
1,000 MW N 2.5% S 30 yr	241,054,000	1.36	1.89	21.73	357.91	96,899,300	1.27	1.77	20.30	334.25

[a] Basis:

Over previously defined power unit life, 30 yr life: 7,000-hr–10 yr, 5,000 hr–5 yr, 3,500 hr–5 yr, 1,500 hr–10 yr.

Midwest plant location, 1975 operating costs not escalated.

Investment and operating cost for disposal of fly ash excluded.

Revenue, $6/ton, 100% H_2SO_4.

Constant labor cost assumed over life of project.

[b] Discounted at 10% to initial year.

[c] Equivalent to discounted process cost over life of power units.

Table 75. Lifetime Byproduct Production and Credit

Case	Years remaining life	Magnesia slurry - regeneration process				Sodium solution - SO_2 reduction process						Catalytic oxidation process			
		Lifetime production short tons,	Net revenue, $/short ton	Cumulative revenue		Lifetime production, short tons		Net revenue, $/short ton		Cumulative revenue		Lifetime production, short tons,	Net revenue, $/short ton	Cumulative revenue	
Coal-fired power unit		100% H_2O_4	100% H_2SO_4	Actual $	Discounted $	Sulfur	Na_2SO_4	Sulfur	Na_2SO_4	Actual $	Discounted $	100% H_2SO_4	100% H_2SO_4	Actual	Discounted $
90% SO_2 removal															
200 MW N 3.5% S	30	823,000	8.00	6,588,000	2,834,500	244,500	96,500	25.00	20.00	8 042,500	3,458,900	817,500	6.00	4,905,000	2,111,400
200 MW E 3.5% S	20	383,000	8.00	3,064,000	1,638,100	114,000	45,000	25.00	20.00	3,750,000	2,001,600	380,500	6.00	2,283,000	1,221,200
500 MW E 3.5% S	25	1,492,000	8.00	11,936,000	5,886,900	442,000	175,000	25.00	20.00	14,550,000	7,177 500	1,484,500	6.00	8,907,000	4,392,300
500 MW N 2.0% S	30	1,149,000	8.00	9,192,000	3,956,400	340,000	135,000	25.00	20.00	11,200,000	4,821,600	1,144,500	6 00	6,867,000	2,953,900
500 MW N 3.5% S	30	2,011,500	8.00	16,092,000	6,923,300	595,000	237,000	25.00	20.00	19,627,500	8,446,300	2,002,500	6.00	12,015,000	5,168,900
500 MW N 5.0% S	30	2,874,000	8.00	22,992,000	9,894,300	851,000	339,000	25.00	20.00	28,055,000	12,069,700	2,859,000	6.00	17,154,000	7,382,800
1,000 MW E 3.5% S	25	2,918,500	8.00	23,348,000	11,517,900	864,000	344,000	25.00	20.00	28,480,000	14,047,200	2,904,500	6.00	17,427,000	8,595,800
1,000 MW N 3.5% S	30	3,889,500	8.00	31,116,000	13,388,000	1,151,000	457,500	25.00	20.00	37,925,000	16,320,200	3,868,500	6.00	23,211,000	9,988,500
80% SO_2 removal															
500 MW N 3.5% S	30	1,788,000	8.00	14,304,000	6,156,700	529,500	211,500	25.00	20.00	17,467,500	7,519,700	—	—	—	—
90% SO_2 removal (fly ash removed by particulate scrubber)															
500 MW E 3.5% S	25	1,492,000	8.00	11,936,000	5,887,000	442,000	175,000	25.00	20.00	14,550,000	7,177,500	—	—	—	—
90% SO_2 removal (without existing electrostatic precipitator)															
500 MW E 3.5% S	25	—	—	—	—	—	—	—	—	—	—	1,484,500	6.00	8,907,000	4,392,400
Oil-fired power unit															
90% SO_2 removal															
200 MW N 2.5% S	30	439,500	8.00	3,516,000	1,511,600	129,500	51,000	25.00	20.00	4,257 500	1,831,800	436,500	6.00	2,619,000	1,128,100
500 MW N 1.0% S	30	430,500	8.00	3,444,000	1,480,600	127,500	51,000	25.00	20.00	4,207,500	1,810,600	426,000	6.00	2,556,000	1,100,200
500 MW N 2.5% S	30	1,072,500	8.00	8,580,000	3,693,100	317,000	126,500	25.00	20.00	10,455,000	4,496,500	1,068,000	6.00	6,408,000	2,756,400
500 MW N 4.0% S	30	1,716,000	8.00	13,728,000	5,906,900	508,500	202,000	25.00	20.00	16,752,500	7,206,300	1,708,500	6.00	10,251,000	4,411,200
500 MW E 2.5% S	25	795,500	8.00	6,364,000	3,139,100	235,000	93,500	25.00	20.00	7,745,000	3,824,000	791,000	6.00	4,746,000	2,342,100
1,000 MW N 2.5% S	30	2,074,500	8.00	16,596,000	7,142,000	614,000	244,500	25.00	20.00	20,240,000	8,707 100	2,064,000	6.00	12,384,000	5,328,400

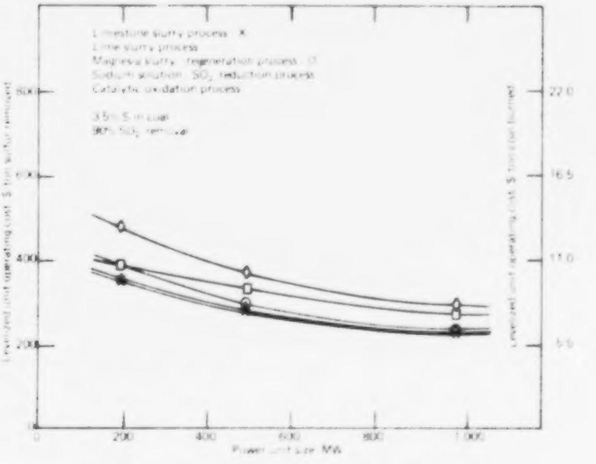


Figure 70. All processes. Effect of power unit size on levelized unit operating cost: new coal-fired units under regulated economics

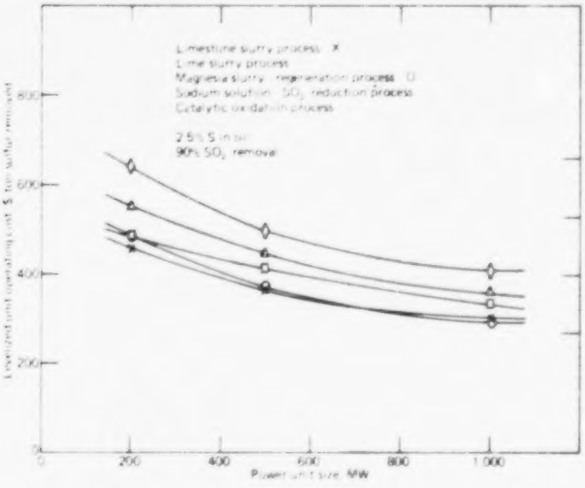


Figure 71. All processes. Effect of power unit size on levelized unit operating cost: new oil-fired units under regulated economics

and oil-fired power units. In comparison with the annual operating costs given earlier, the relative ranking is shifted. For the catalytic oxidation process these costs decrease with increasing sulfur content of fuel for both coal- and oil-fired power units, whereas, for all other processes, these costs increase.

Table 76 shows the effect of designing for 80% SO_2 removal instead of the assumed standard of 90% on cumulative lifetime discounted process costs for the limestone, lime, magnesia, and sodium processes. Designing for 80% SO_2 removal in comparison to 90% results in a lifetime savings of only 3.6% to 5.8% of the projected costs corresponding to 90% SO_2 removal.

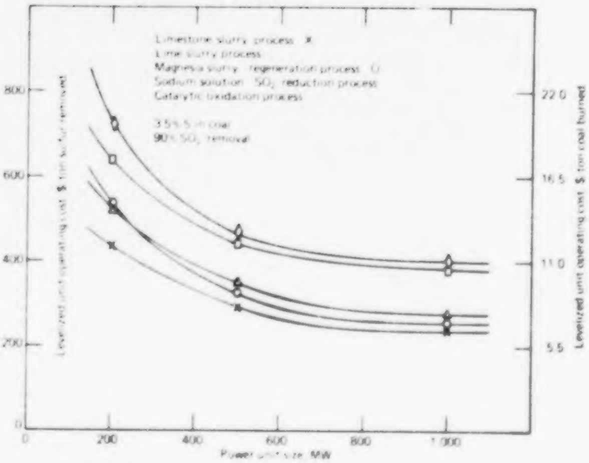


Figure 72. All processes. Effect of power unit size on levelized unit operating cost: existing coal-fired units under regulated economics

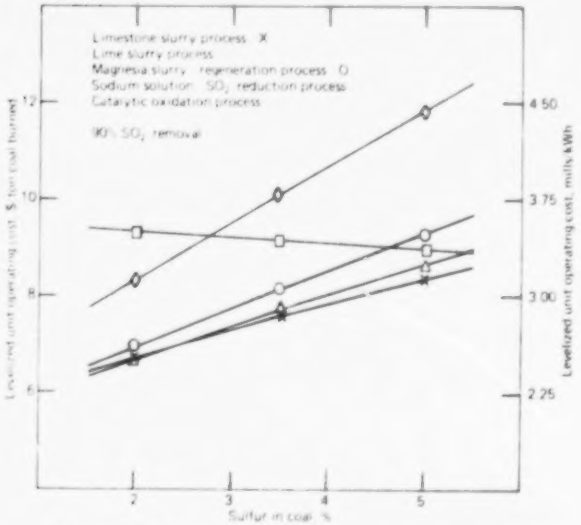


Figure 73. All processes. Effect of sulfur content of coal on levelized unit operating cost: new 500-MW coal-fired units under regulated economics

Given in table 77 is a comparison of the lifetime operating costs for existing units requiring additional facilities for removal of particulates with the standard case which assumes that existing electrostatic precipitators on existing units are adequate. The effect is similar to that shown for the investment and annual operating costs; additional costs for particulate removal are the least for the lime slurry process because only minor modifications in design and operation are required.

Table 76. Comparison of Cumulative Lifetime Discounted Process Costs for SO_2 Removal Processes at 90% and 80% SO_2 Removal

Process	Cumulative lifetime discounted process cost, \$ 500 MW, new 3.5% S coal-fired units 90% SO_2 removal	80% SO_2 removal	Cumulative lifetime discounted cost savings resulting from design for 80% SO_2 removal compared to 90% \$	%
Limestone slurry	78,439,900	75,259,300	3,180,600	4.1
Lime slurry	79,593,300	76,687,900	2,905,400	3.6
Magnesia slurry - regeneration	84,249,500	81,119,800	3,129,700	3.7
Sodium solution - SO_2 reduction	104,292,300	98,245,000	6,047,300	5.8

Table 77. Cumulative Lifetime Discounted Process Costs for SO_2 Removal Installations on Existing Power Units Requiring Additional Facilities for Removal of Particulates–Comparison with Standard[a]

Process	Cumulative discounted process cost, \$ 500-MW existing 3.5% S coal-fired units Requiring additional particulate removal facilities	Standard[a]	Difference in projected cumulative lifetime discounted process costs \$	%
Limestone slurry	87,143,300	70,550,000	16,593,300	23.5
Lime slurry	84,924,200	84,117,600	806,600	1.0
Magnesia slurry - regeneration	93,875,800	78,292,200	15,583,600	19.9
Sodium solution - SO_2 reduction	130,713,900	113,985,500	16,728,400	14.7
Catalytic oxidation	119,124,800	106,607,800	12,517,000	11.7

[a] Standard case assumes that the existing electrostatic precipitator is adequate for existing units.

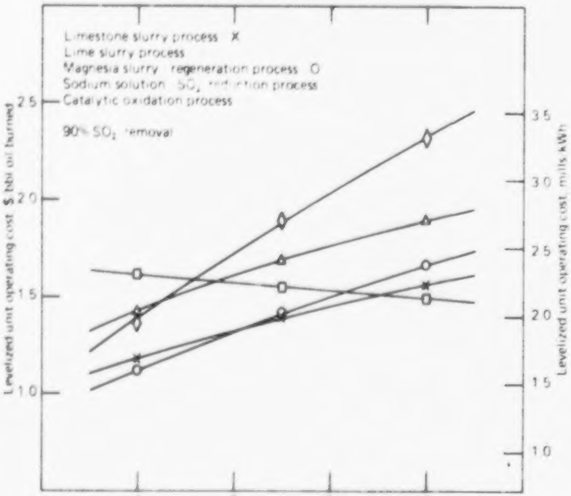


Figure 74. All processes. Effect of sulfur content of oil on levelized unit operating cost: new 500-MW oil-fired units under regulated economics

The comparison between cumulative lifetime discounted process costs for the limestone and lime processes corresponding to off-site and on-site waste solids disposal shown in table 78 indicates that the cumulative discounted costs for off-site waste solids disposal are only 1.6% to 2.5% greater than for the on-site disposal variations. This result is somewhat surprising in comparison with the 6.2% to 8.0% higher annual operating costs projected for off-site disposal variations. Obviously, the effect of declining on-stream time compiled with the off-site disposal fee per ton of wet solids narrows the difference.

The sensitivity of lifetime operating costs to parameter changes not readily visible in the results of the case variations are discussed below.

The effect of declining remaining life of a power unit on levelized unit operating costs for the limestone slurry process is shown in figure 75.

Figure 76 shows the overall range of discounted process costs which could be expected for the limestone slurry process over the life of the power unit when both high and low price limestone and on-site and off-site disposal variations are considered simultaneously. In comparing the results, it should be remembered that the majority of the

Table 78. Comparison of Cumulative Lifetime Discounted Process Cost for Limestone and Lime SO_2 Removal Processes Utilizing On-site and Off-site Waste Solids Disposal

Process	Cumulative discounted process cost, $ 500-MW, new 3.5% S coal-fired units		Cumulative discounted lifetime savings resulting from design for on-site as opposed to off-site waste solids disposal	
	Off-site	On-site	$	%
Limestone slurry	80,426,200	78,439,900	1,986,300	2.5
Lime slurry	80,903,300	79,593,300	1,310,000	1.6

case variations of limestone and lime slurry processes correspond to power units which utilize an on-site pond for waste disposal. If, for a given power plant, land is not available, alternate methods of disposal would need to be used.

Figures 77 through 81 show the sensitivity of lifetime levelized unit operating costs to variations in total capital investment for the five processes. These relationships can be used for projecting the range of levelized unit operating costs which may be encountered as a result of possible inaccuracies in the projected investment, or with variations in project scope.

The effects of variations in product revenue on levelized unit operating costs for the magnesia and sodium scrubbing processes, and the catalytic oxidation process are given in figures 82 through 87. The revenues are varied from what is considered to be a minimum price in a saturated market up to the current list price. It can be seen that the sensitivity of levelized unit operating costs to variations in product revenue is greater for the sulfuric acid than the sulfur processes. This is an important point when the weight relationship between sulfur and sulfuric acid is considered; 1 ton of sulfur is equivalent to approximately 3 tons of sulfuric acid.

Figure 88 shows the effect of annual labor cost escalation on the cumulative lifetime discounted costs of the limestone and sodium scrubbing processes (a) without labor escalation and (b) with labor cost escalation rates of 7.5% per year over the life of the power unit. The relationship shows that there is an increase of about 7%-10% in the projected lifetime operating costs with escalation included.

The effect of variations in the cost of money on levelized unit operating costs for the five processes are presented in figures 89 through 93. The relative variations are obviously the greatest for the processes which require the greatest capital investment.

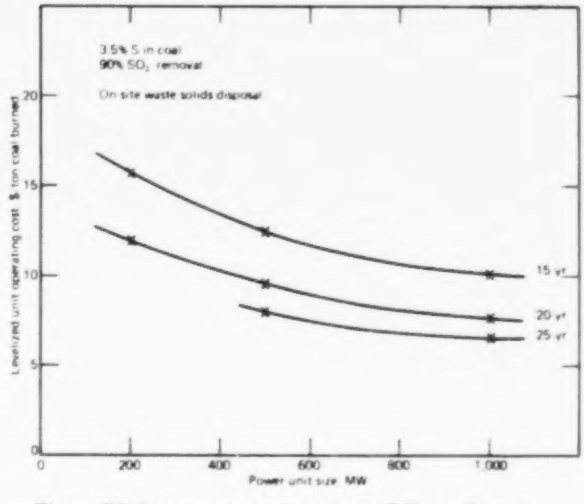


Figure 75. Limestone slurry process. Effect of years remaining life on levelized unit operating cost: existing coal-fired units under regulated economics

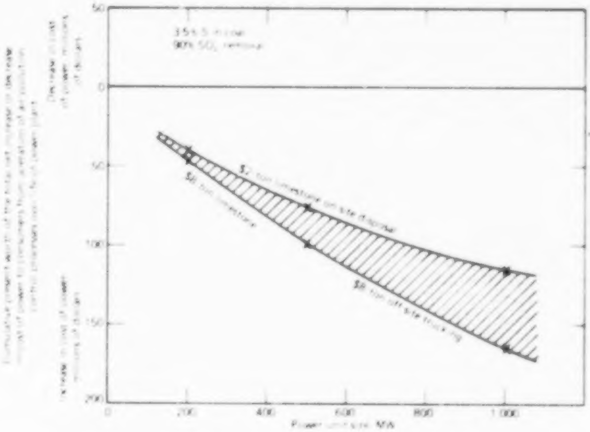


Figure 76. Limestone slurry process. Effect of variation in limestone price and in disposal method on cumulative present worth of total increase or decrease in cost of power to consumers: new coal-fired units under regulated economics

ACCURACY OF RESULTS

When the results of a comprehensive cost evaluation are widely distributed, questions regarding estimate accuracy are almost always raised. For SO_2 processes, such questions are especially relevant since many previous process cost estimates have been inconsistent.

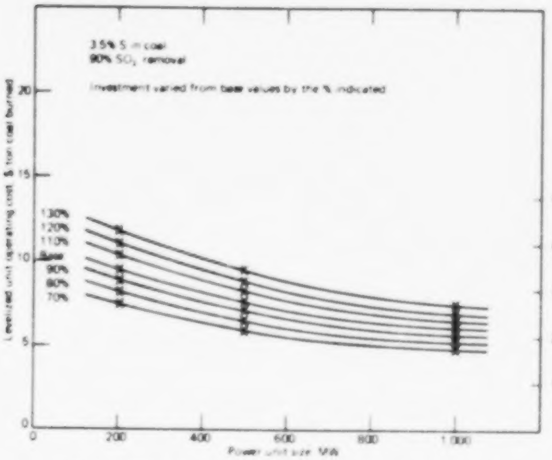


Figure 77. Limestone slurry process. Effect of variations in investment on levelized unit operating cost: new coal-fired units under regulated economics

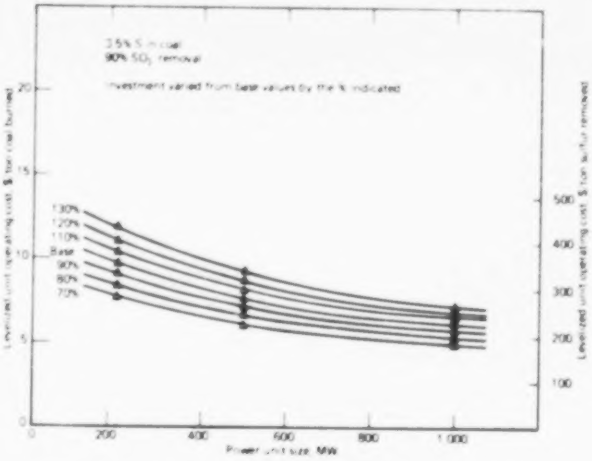


Figure 78. Lime slurry process. Effect of variations in investment on levelized unit operating cost: new coal-fired units under regulated economics

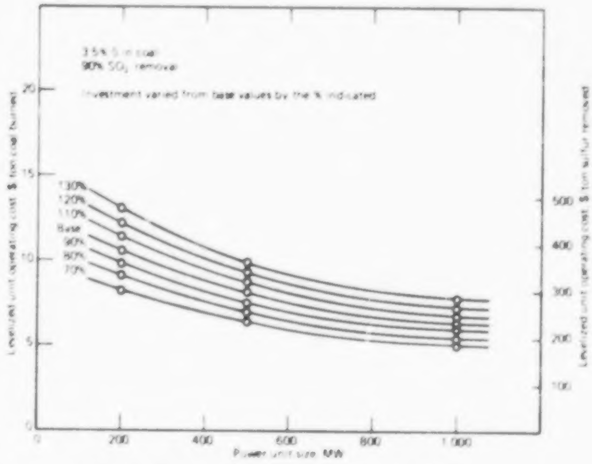


Figure 79. Magnesia slurry - regeneration process. Effect of variations in investment on levelized unit operating cost: new coal-fired units under regulated economics

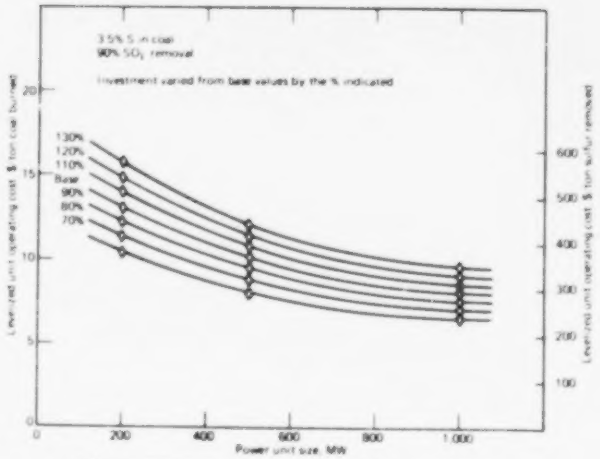


Figure 80. Sodium solution - SO_2 reduction process. Effect of variations in investment on levelized unit operating cost: new coal-fired units under regulated economics

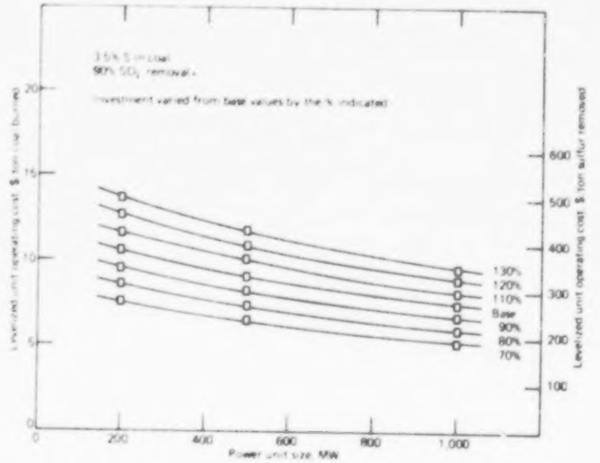


Figure 81. Catalytic oxidation process. Effect of variations in investment on levelized unit operating cost: new coal-fired units under regulated economics

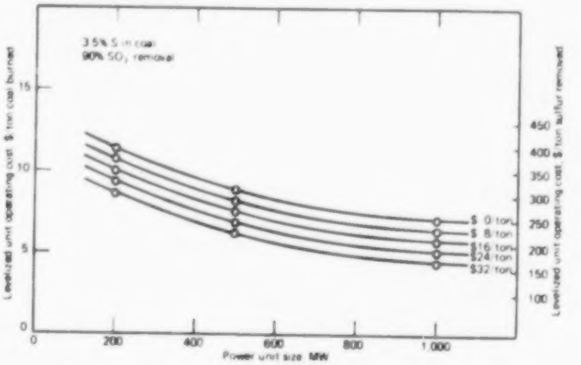


Figure 82. Magnesia slurry - regeneration process. Effect of variations in sulfuric acid revenue on levelized unit operating cost: new coal fired units under regulated economics

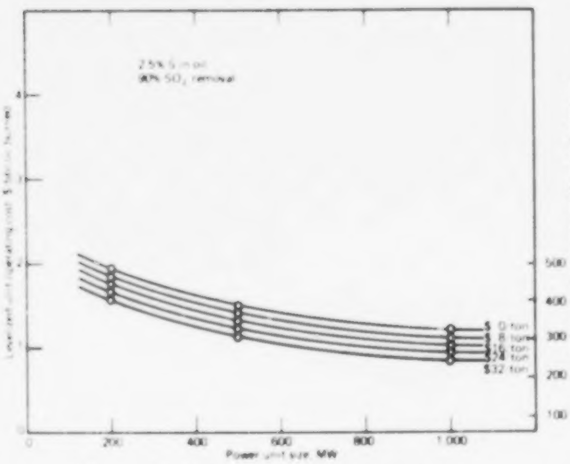


Figure 83. Magnesia slurry - regeneration process. Effect of variations in sulfuric acid revenue on levelized unit operating cost: new oil-fired units under regulated economics

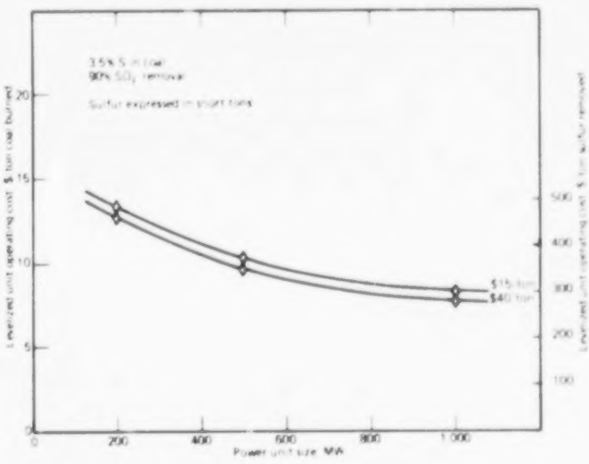


Figure 84. Sodium solution - SO_2 reduction process. Effect of variations in sulfur revenue on levelized unit operating cost: new coal-fired units under regulated economics

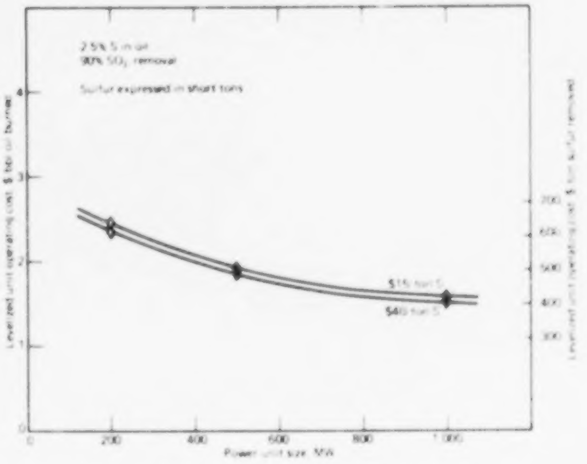


Figure 85. Sodium solution - SO_2 reduction process. Effect of variations in sulfur revenue on levelized unit operating cost: new oil-fired units under regulated economics

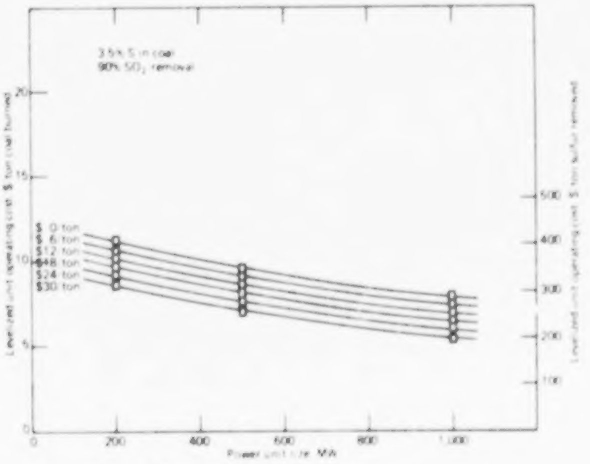


Figure 86. Catalytic oxidation process. Effect of variations in sulfuric acid revenue on levelized unit operating cost: new coal-fired units under regulated economics

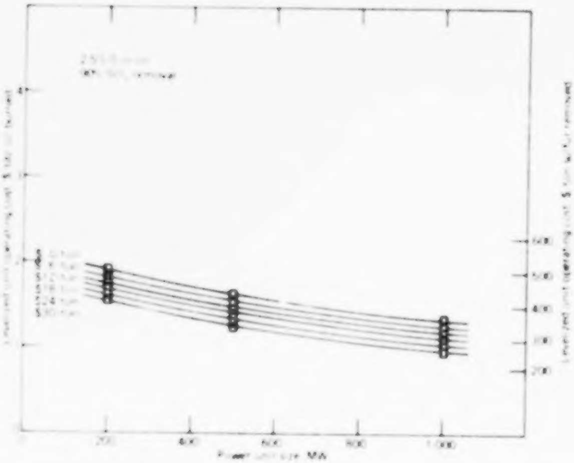


Figure 87. Catalytic oxidation process. Effect of variations in sulfuric acid revenue on levelized unit operating cost: new oil-fired units under regulated economics

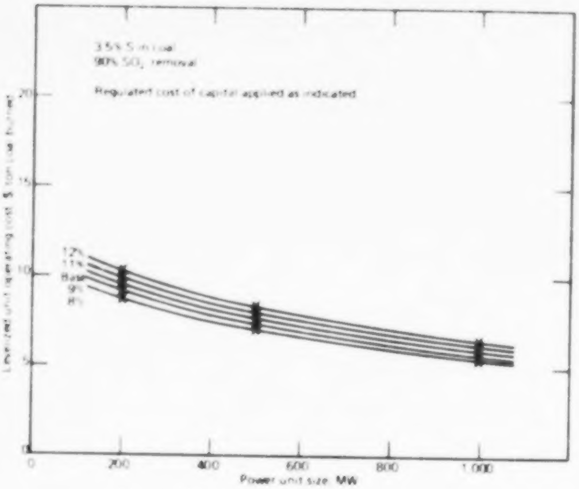


Figure 89. Limestone slurry process. Effect of variations in cost of money on levelized unit operating cost: new coal-fired units under regulated economics

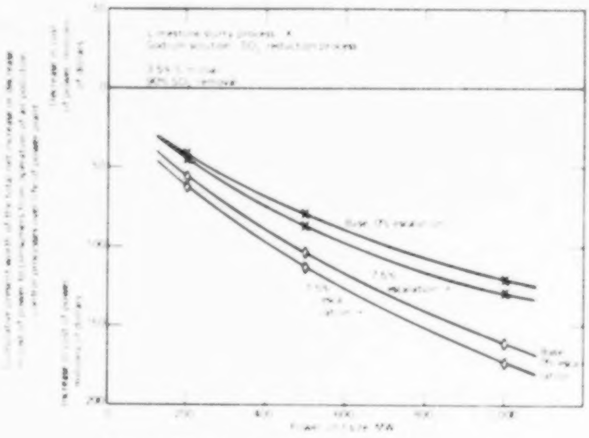


Figure 88. Limestone slurry and sodium solution - SO₂ reduction processes. Effect of annual labor cost escalation on cumulative present worth of total increase or decrease in cost of power to consumers: new coal-fired units under regulated economics

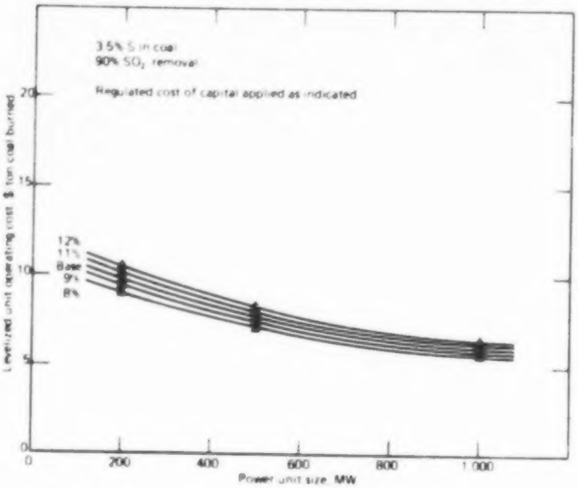


Figure 90. Lime slurry process. Effect of variations in cost of money on levelized unit operating cost: new coal-fired units under regulated economics

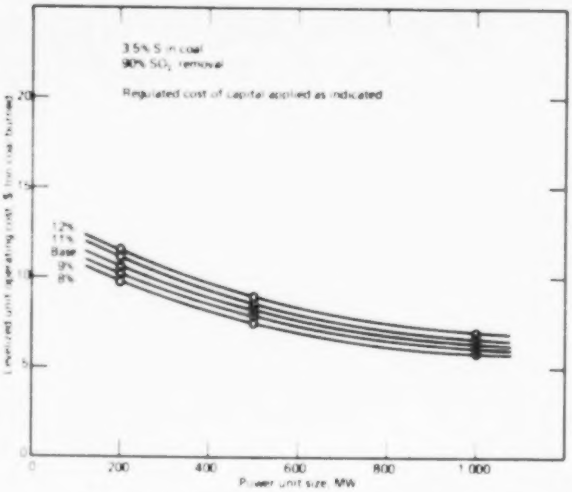


Figure 91. Magnesia slurry - regeneration process. Effect of variations in cost of money on levelized unit operating cost: new coal-fired units under regulated economics

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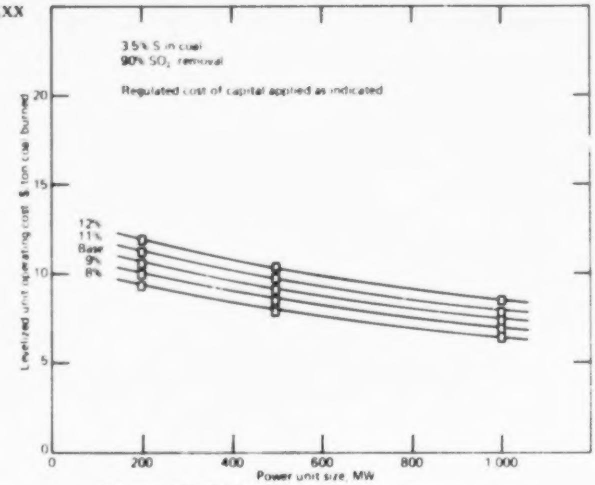

Figure 93. Catalytic oxidation process. Effect of variations in cost of money on levelized unit operating cost: new coal-fired units under regulated economics

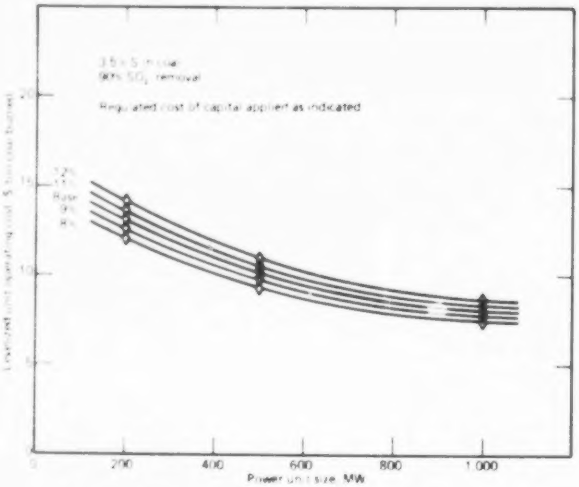

Figure 92. Sodium solution - SO_2 reduction process. Effect of variations in cost of money on levelized unit operating cost: new coal-fired units under regulated economics

Several full-scale stack gas SO_2 removal projects are now under way and as costs for these become available, comparisons with the results of this study are to be expected. In many cases, however, such efforts will be misleading if care is not taken to make sure the scope of work is directly comparable. For instance, the base case (500-MW, 3.5% S new coal-fired unit) capital investment for limestone slurry scrubbing derived in this study is $50.3/kW; however, as can be seen in table 79, with some changes in scope, the cost could rise to $113.0/kW or higher depending on a variety of inputs.

The actual costs of installing and operating several large-scale systems will be the best measure of accuracy of these projections and, even then, the effects of further process development and inflation will have to be examined. However, considering the current status of process technologies, the estimates in this study should be more accurate than any previously published.

Recognition should be given to the factors having the greatest degree of uncertainty on the costs of these systems. Until demonstrated performance is obtained, there are numerous areas of concern in all the processes; however, deviations in the following factors are expected to have the largest impact.

Investment

Mist elimination in slurry scrubbing processes.
System reliability (need for redundancy) all processes.
Materials of construction all processes.
Solids disposal system in limestone and lime processes.

Operating Cost

Raw material and solids disposal cost for limestone and lime processes.
Recycle MgO losses in magnesia process.
Process maintenance all systems.
Catalyst cleaning and losses in Cat-Ox process.
Oxidation losses in sodium scrubbing process.
Energy costs all systems.

Table 79. Limestone Slurry Process Investment with Modified Project Scope

	Investment, $/kW
Base investment—limestone slurry process (including fly ash removal but not disposal) 500-MW new coal-fired unit burning coal with 3.5% S, 12% ash, 90% SO_2 removal, 30-year life, 127,500 hours operation, on-site solids disposal, proven system, only pumps spared, no bypass ducts, experienced design and construction team, no overtime, 3-year program, 5% per year escalation, mid-1974 cost basis for scaling	50.30
Overtime to accelerate project or cover local demand requirements (50% of construction labor requirements)	3.20
Research and development costs for first of a kind process technology (as allowed by FPC accounting practice)	5.00
Power generation capital for lost capacity (normally covered by appropriate operating costs for power used in process)	4.50
Reliability provisions with added redundancy of scrubbers, other equipment, ducts and dampers, instrumentation for changeover (assumes no permission to run power plant without meeting SO_2 removal emission standards at all times)	6.00
Additional bypass ducts and dampers	2.00
Retrofit difficulty—moderate, space available beyond stack, less than three shutdowns required for tie-ins, field fabrication feasible	10.00
Fly ash pond including closed-loop provisions	5.50
500-ft stack added to project cost	6.00
Air quality monitoring system, 2-15 mile radius, 10 stations	0.70
Cost escalation of 10%/year instead of 5%	4.80
Possible delay of up to 2 years in equipment and material deliveries (1977 completion instead of 1975)	15.00
Total	113.00

Sales value of acid, sulfur, and sodium sulfate.

Investment changes caused by process uncertainties would normally be covered by the estimate contingency and modifications after startup since the magnitude of these components reflect process definition. With the premise that the designs in this study are proven, not first of a kind, only nominal provisions for contingency (10% of direct cost) and modifications after startup (10.8% of direct cost) are included in the base estimates. However, further refinement will likely evolve during continued process development. Therefore, projections of total capital investment variance based on the present "state of the art" and the data available to TVA are given below for the base case of each process.

Process	% variance from base total capital investment due to data availability and process development status
Limestone slurry	+15, -5
Lime slurry	+15, -5
Magnesia slurry - regeneration	+20, -10
Sodium solution - SO_2 reduction	+25, -10
Catalytic oxidation	+15, -5

For the time and money spent to prepare the investment estimates and the state of process development, qualified texts (4, 23, 33, 34) on the cost estimation indicate these estimates should have an accuracy range of +25% to 30% to -10% to -15%. To give the reviewer better perspective on the reliability of these factors, an analysis of accuracy was made on the base case investment for each process. In preparing this analysis, additional projections of possible variances in the major estimate components were necessary. The following variances from the base case are considered to be reflective of information utilized.

Component	Variance, %
Directs	
Process equipment	
Vendor data	+20, -10
Previous purchases, escalated	+10, -10
Publications	+30, -20
Materials	+20, -15
Construction labor	+25, -15
Site preparation	+100, -25
Land	+200, -70
Construction facilities	+60, -40
Indirects	
Engineering, design, and supervision	+50, -20
Construction field expense	+50, -20
Contractors fees	+50, -20
Contingency	Depends on process definition
Allowance for startup	Depends on process definition

For a 3-year project, interest during construction could be expected to vary from 6% to 10% of total fixed investment.

Using these inputs, calculated projections of maximum and minimum investment which reflect accumulation of individual component deviations for each process are shown in tables 80 through 84. The cumulative variances are obviously too large because not all factors will vary in the same direction and to the extreme values. Therefore, an educated judgment was used to select the most likely values for ranges in investment accuracy for each process. These are stated in table 85.

Because the estimates for case variations are factored, their accuracy must be considered as less than the base case. Since the accuracy of operating cost results would depend largely on those for investment, and because almost every unit of operating cost is a variable, estimates of operating cost accuracy are not projected. The effects of variations in the primary operating cost factors are shown in the sensitivity analyses previously presented.

Table 80. Limestone Slurry Process–Investment Estimate Accuracy Analysis

Component	Investment, $		
	Minimum	Base case[a]	Maximum
Direct costs			
Process equipment	4,237,000	4,724,000	5,571,000
Materials	2,621,000	3,083,000	3,700,000
Construction labor	3,154,000	3,710,000	4,638,000
Site preparation	2,525,000	3,367,000	6,734,000
Land	126,000	420,000	1,260,000
Construction facilities	459,000	765,000	1,224,000
Subtotal direct investment	13,122,000	16,069,000	23,127,000
Indirect costs			
Engineering design and supervision	1,157,000	1,446,000	2,169,000
Construction field expense	1,414,000	1,768,000	2,652,000
Contractor fees	642,000	803,000	1,205,000
Contingency	1,607,000	1,607,000	3,494,000
Subtotal fixed investment	17,942,000	21,693,000	32,647,000
Allowance for startup and modifications	477,000	1,735,000	3,622,000
Interest during construction	1,077,000	1,735,000	3,265,000
Total capital investment	19,496,000	25,163,000	39,534,000
Percent of variance	-22.5	0	+57.1

[a] 500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal.

Table 81. Lime Slurry Process–Investment Estimate Accuracy Analysis

Component	Investment, $		
	Minimum	Base case[a]	Maximum
Direct costs			
Process equipment	3,029,000	3,375,000	3,962,000
Materials	2,694,000	3,169,000	3,803,000
Construction labor	3,207,000	3,773,000	4,717,000
Site preparation	2,223,000	2,964,000	5,928,000
Land	107,000	355,000	1,065,000
Construction facilities	409,000	682,000	1,091,000
Subtotal direct investment	11,669,000	14,318,000	20,566,000
Indirect costs			
Engineering design and supervision	1,031,000	1,289,000	1,934,000
Construction field expense	1,260,000	1,575,000	2,363,000
Contractor fees	573,000	716,000	1,074,000
Contingency	1,432,000	1,432,000	3,114,000
Subtotal fixed investment	15 965,000	19,330,000	29,051,000
Allowance for startup and modifications	425,000	1,546,000	3,228,000
Interest during construction	958,000	1,546,000	2,905,000
Total capital investment	17,348,000	22,422,000	35,184,000
Percent of variance	-22.6	0	+56.9

[a] 500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal.

Table 82. Magnesia Slurry - Regeneration Process—Investment Estimate Accuracy Analysis

Component	Investment, $		
	Minimum	Base case[a]	Maximum
Direct costs			
Process equipment	4,940,000	5,509,000	6,517,000
Materials	3,383,000	3,980,000	4,776,000
Construction labor	4,781,000	5,625,000	7,031,000
Site preparation	314,000	419,000	838,000
Land	7,000	23,000	69,000
Construction facilities	467,000	778,000	1,245,000
Subtotal direct investment	13,892,000	16,334,000	20,476,000
Indirect costs			
Engineering design and supervision	1,438,000	1,797,000	2,696,000
Construction field expense	1,438,000	1,797,000	2,696,000
Contractor fees	654,000	817,000	1,226,000
Contingency	1,633,000	1,633,000	4,274,000
Subtotal fixed investment	19,055,000	22,378,000	31,368,000
Allowance for startup and modifications	0	2,238,000	4,879,000
Interest during construction	1,143,000	1,790,000	3,137,000
Total capital investment	20,198,000	26,406,000	39,384,000
Percent of variance	-23.5	0	+49.1

[a] 500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 15.8 tons/hr 100% H_2SO_4.

Table 83. Sodium Solution - SO_2 Reduction Process—Investment Estimate Accuracy Analysis

Component	Investment, $		
	Minimum	Base case[a]	Maximum
Direct costs			
Process equipment	7,610,000	8,487,000	10,105,000
Materials	2,934,000	3,452,000	4,142,000
Construction labor	4,853,000	5,709,000	7,136,000
Site preparation	218,000	291,000	582,000
Land	7,000	24,000	72,000
Construction facilities	539,000	898,000	1,437,000
Subtotal direct investment	16,161,000	18,861,000	23,474,000
Indirect costs			
Engineering design and supervision	1,660,000	2,075,000	3,113,000
Construction field expense	1,660,000	2,075,000	3,113,000
Contractor fees	754,000	943,000	1,415,000
Contingency	1,886,000	1,886,000	5,697,000
Subtotal fixed investment	22,121,000	25,840,000	36,812,000
Allowance for startup and modifications	0	2,584,000	6,395,000
Interest during construction	1,327,000	2,067,000	3,681,000
Total capital investment	23,448,000	30,491,000	46,888,000
Percent of variance	-23.1	0	+53.8

[a] 500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 4.7 tons/hr S produced.

Table 84. Catalytic Oxidation Process—Investment Estimate Accuracy Analysis

Component	Investment, $		
	Minimum	Base case[a]	Maximum
Direct costs			
Process equipment	10,025,000	11,188,000	13,468,000
Materials	3,771,000	4,437,000	5,324,000
Construction labor	6,984,000	8,217,000	10,271,000
Site preparation	223,000	297,000	594,000
Land	6,000	21,000	63,000
Construction facilities	725,000	1,208,000	1,933,000
Subtotal direct investment	21,734,000	25,368,000	31,653,000
Indirect costs			
Engineering design and supervision	2,232,000	2,790,000	4,185,000
Construction field expense	2,232,000	2,790,000	4,185,000
Contractor fees	1,014,000	1,268,000	1,902,000
Contingency	2,537,000	2,537,000	5,742,000
Subtotal fixed investment	29,749,000	34,753,000	47,667,000
Allowance for startup and modifications	1,338,000	3,475,000	6,680,000
Interest during construction	1,785,000	2,780,000	4,767,000
Total capital investment excluding catalyst	32,872,000	41,008,000	59,114,000
Catalyst	1,555,000	1,728,000	2,074,000
Total capital investment	34,427,000	42,736,000	61,188,000
Percent of variance	-19.4	0	+43.2

[a] 500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 15.7 tons/hr 100% H_2SO_4.

Table 85. Projected Overall Investment Estimate Accuracy Based on Available Data and Depth of Investigation

Process	% range
Limestone slurry	+20 to -5
Lime slurry	+20 to -10
Magnesia slurry - regeneration	+25 to -15
Sodium solution - regeneration	+25 to -10
Catalytic oxidation (Cat-Ox)	+20 to -10

Conclusions

From the multitude of data generated in this study, a large number of conclusions can be derived. The most important ones are listed below.

INVESTMENT

1. For new coal-fired systems, the lime scrubbing process has the lowest investment and catalytic oxidation has the highest (figure 33). The limestone and magnesia processes are less expensive than the lime process on oil-fired units (figure 34) because lime process definition specifies two stages of venturi scrubbing for SO_2 removal in comparison to one SO_2 scrubbing stage for the limestone and magnesia processes. Limestone investment is slightly lower than magnesia investment for both 3.5% S coal-fired units and 2.5% S oil-fired units. Costs for all four wet scrubbing processes range within 22% to 36% of each other depending upon the fuel.
2. As sulfur content of fuel varies, the relative investment ranking of the wet scrubbing processes changes; lime is still lowest for coal-fired units (figure 36), but for oil-fired units (figure 37), limestone or magnesia investments are the lowest. Although these investments are very close throughout the range of sulfur values, magnesia investment is slightly lower for the low-sulfur oil, and limestone investment is slightly lower for the medium- and high-sulfur oils.
3. The Cat-Ox process has the poorest investment economy of scale (unit size) of all five systems (figures 33 and 34); however, for sulfur variations, Cat-Ox has the best scale factor (figures 36 and 37). A reheat (existing) Cat-Ox system requiring full particulate removal facilities to 0.005 gr/scf was found to be only 2.5% higher than a new integrated unit (table 31).
4. Plant age is an important factor only in the limestone and lime processes (figure 42) where pond size depends on remaining plant life; older (less remaining life) units should use limestone or lime processes.
5. Removal of only 80% of the SO_2 (which would meet emission standards for 3.5% S coal-fired units) instead of 90% decreases investment by only 3% to 5% (table 33).

OPERATING COST

1. For new 3.5% S coal-fired power units under the premises used, the limestone process has the lowest annual operating cost and sodium the highest (figure 43). For 2.5% S oil-fired units, limestone and Cat-Ox operating costs are very competitive, ranking the lowest of the five processes and sodium the highest (figure 44). Lifetime operating costs are lowest for the limestone slurry process for coal-fired power units, and sodium the highest (figure 70). However, the magnesia process is competitive with limestone and lime operating costs for the larger size units. For new 2.5% S oil-fired units, lifetime limestone operating costs are lowest for 200- and 500-MW units, whereas, magnesia process operating cost is lowest for 1,000-MW units (figure 71).
2. As sulfur content of fuel varies, the relative operating costs for all five systems change. However, the most dramatic change is reflected in the lifetime operating cost for the Cat-Ox process. The Cat-Ox process lifetime operating cost is the highest of the five processes for low sulfur oil-fired units, whereas, for high sulfur oils it improves in rank and becomes the lowest (figure 74). This is one of the most interesting results of the study. The heat credit for Cat-Ox becomes quite significant at high sulfur levels. Considering the overall range of sulfur contents for both coal- and oil-fired units, situations exist for which lifetime operating costs for four of the five processes are lowest in rank (figures 73 and 74).
3. Raw material costs for the lime and sodium processes are highest of the five processes, whereas, those for the magnesia and Cat-Ox processes are lowest (tables 59-68).
4. Sodium scrubbing has the highest total labor cost and Cat-Ox the lowest; however, labor is one of the smallest components (1%-3% of total annual operating cost) for all five processes (tables 59-68).
5. Energy costs are significant for all systems; applications of sodium scrubbing on existing units require the greatest amount of energy (35% of total operating cost). The magnesia process is also energy intensive; the Cat-Ox system uses the lowest amount (5%) (tables 59-68).

6. Although expense for antioxidant (sodium system) is high, it is justified to keep sulfate formation down and save Na_2CO_3 makeup (figure 66).
7. Maintenance is quite significant ranging from 7% of the total annual operating cost for the Cat-Ox reheat process (existing unit) to 17% for the limestone slurry process (new unit) (tables 59-68).
8. Capital charges are the largest individual component of operating cost for all five processes (tables 59-68). For new Cat-Ox systems, base case capital charges are 72% of the total annual operating costs. For the other processes, base case capital charges are in the range of 39% to 50%. A change in depreciation rate or cost of money will obviously affect Cat-Ox the most.
9. For high operating on-stream times, on-site solids disposal is less expensive than off-site (table 58), however, the reverse may be true for low operating times.
10. Only about 4% to 6% of total operating cost is saved when 80% SO_2 removal is provided instead of 90% (table 76).
11. A Cat-Ox process on an existing plant has a 40% greater annual operating cost than on a new system (table 55). This is caused by the high energy required for stack gas reheat from 310° to 890°F prior to conversion of SO_2 to SO_3.
12. As would be expected the scrubbing steps of each process are the highest cost operations (tables 59-68).
13. For the energy intensive processes, oil-fired systems are at a disadvantage because of the high cost of fuel oil relative to coal (\$1.53/MM Btu compared to \$0.54/MM Btu).
14. Because 3 tons of sulfuric acid can be made from approximately 1 ton of sulfur, every dollar increase in net sales revenue for acid would require an equivalent \$3 increase in value of sulfur to obtain the same revenue. Current prices of sulfuric acid in small quantities can be as high as \$35/ton; however, the best sulfur prices would probably be less than \$50/ton. If in the sodium scrubbing process, an acid plant were substituted for a sulfur production unit, approximately \$335,000 a year operating cost could be saved; however, this is only 3% of the total operating cost. Sale of byproducts at the values assumed in the study would reduce the base case lifetime operating cost 7.2% for the magnesia, 7.1% for the sodium, and 4.9% for the Cat-Ox process (tables B-117, B-165, and B-213).
15. Because of product revenues, the relative ranking of the magnesia scrubbing process on oil-fired units improves under lifetime operating costs until it is the lowest cost system above 800-MW size (figure 71).
16. Labor cost escalation (7.5% per year) over a 30-year process life would add about 7% to 10% to total process cost (figure 88).
17. Regardless of which process is utilized, the increase in the cost of power to consumers for the base case is projected to range from 2.86 to 3.80 mills/kWh. For all case variations, projected costs could range from 1.57 to 7.90 mills/kWh (tables 70-74).
18. Because the relative rankings of these five processes are so variable, and the results so close, this evaluation will need to be updated as process definitions stabilize, improvements are developed, and economic conditions change.

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APPENDIX A

GENERAL CONVERSION FACTORS

EPA policy is to express all measurements in Agency documents in metric units. Values in this report are given in British units for the convenience of engineers and other scientists accustomed to using the British system. The following conversion factors may be used to provide metric equivalents.

	British		Metric	
	Multiply	By	To obtain	
ac	acre	0.405	hectare	ha
bbl	barrels of oil	158.97	liters	l
Btu	British Thermal Unit	252	gram-calories	g-cal
°F	degrees Fahrenheit-32	0.5555	degrees Centigrade	°C
ft	feet	30.48	centimeters	cm
ft^2	square feet	0.0929	square meters	m^2
ft^3	cubic feet	0.02832	cubic meters	m^3
ft/min	feet per minute	0.508	centimeters per second	cm/sec
ft^3/min	cubic feet per minute	0.000472	cubic meters per second	m^3/sec
gal	gallons	3.785	liters	l
gpm	gallons per minute	0.06308	liters per second	l/sec
gr	grains (troy)	0.0648	grams	g
gr/ft^3	grains per cubic foot	2.288	grams per cubic meters	g/m^3
hp	horsepower	0.7457	kilowatts	kW
in	inches	2.54	centimeters	cm
lb	pounds	0.4536	kilograms	kg
lb/ft^3	pounds per cubic foot	16.02	kilograms per cubic meter	Kg/m^3
lb/hr	pounds per hour	0.126	grams per second	g/sec
mi	miles	1609.	meters	m
rpm	revolutions per minute	0.1047	radians per second	rad/sec
scfm	standard cubic feet per minute (32° F)	1.695	normal cubic meters per hour (0° C)	Nm^3/hr
ton	tons (short)[a]	0.90718	metric tons	t
ton, long	tons (long)[a]	1.016	metric tons	t
ton/hr	tons per hour	0.252	kilograms per second	kg/sec

[a] All tons, including tons of sulfur, are expressed in short tons in this report.

APPENDIX B

COST TABLES

Table B-1. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(200-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	234,000	2.9
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	472,000	5.9
Particulate scrubbers and inlet ducts (2 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	1,381,000	17.4
Sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	2,048,000	25.9
Stack gas reheat (2 indirect steam reheaters)	243,000	3.1
Fans (2 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	377,000	4.8
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	2,275,000	28.8
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	46,000	0.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	458,000	5.8
Construction facilities	377,000	4.8
Subtotal direct investment	7,911,000	100.0
Engineering design and supervision	870,000	11.0
Construction field expense	1,028,000	13.0
Contractor fees	554,000	7.0
Contingency	870,000	11.0
Subtotal fixed investment	11,233,000	142.0
Allowance for startup and modifications	899,000	11.4
Interest during construction (8% annum rate)	899,000	11.4
Total capital investment	13,031,000	164.8

[a] Basis:
Stack gas reheat to 175° F by indirect steam reheat
Disposal pond located 1 mile from power plant
Midwest plant location represents project beginning mid 1972, ending mid 1975. Average cost basis for scaling, mid 1974
Minimum in process storage, only pumps are spared
Investment requirements for disposal of fly ash excluded
Construction labor shortages with accompanying overtime pay incentive not considered

Table B-2. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	71.6 M tons	4.00/ton	286,400	7.30
Subtotal			286,400	7.30
Conversion costs				
Operating labor and supervision	17,520 man hr	8.00/man hr	140,200	3.58
Utilities				
Steam	201,500 M lb	0.80/M lb	161,200	4.11
Process water	102,300 M gal	0.08/M gal	8,200	0.21
Electricity	32,180,000 kWh	0.011/kWh	354,000	9.03
Maintenance				
Labor and material, .09 × 7,911,000			712,000	18.15
Analyses			24,000	0.61
Subtotal conversion costs			1,399,600	35.69
Subtotal direct costs			1,686,000	42.99
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,941,600	49.51
Overhead				
Plant, 20% of conversion costs			279,900	7.14
Administrative, 10% of operating labor			14,000	0.36
Subtotal indirect costs			2,235,500	57.01
Total annual operating cost			3,921,500	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	7.31	2.80	30.45	267.31

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175 F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $13,031,000; subtotal direct investment, $7,911,000.
Working capital, $283,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-3

LIMESTONE SLURRY PROCESS, 200 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 14031000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	536700	14700	84200	0.0	5277200	0	5277200	5277200
2	7000	12880000	536700	14700	84200	0.0	5186900	0	5186900	10464100
3	7000	12880000	536700	14700	84200	0.0	5096500	0	5096500	15560600
4	7000	12880000	536700	14700	84200	0.0	5006200	0	5006200	20566800
5	7000	12880000	536700	14700	84200	0.0	4915800	0	4915800	25482600
6	7000	12880000	536700	14700	84200	0.0	4825500	0	4825500	30308100
7	7000	12880000	536700	14700	84200	0.0	4735100	0	4735100	35043200
8	7000	12880000	536700	14700	84200	0.0	4644800	0	4644800	39688000
9	7000	12880000	536700	14700	84200	0.0	4554400	0	4554400	44242400
10	7000	12880000	536700	14700	84200	0.0	4464100	0	4464100	48706500
11	5000	9200000	383300	10500	60200	0.0	3919600	0	3919600	52626100
12	5000	9200000	383300	10500	60200	0.0	3829200	0	3829200	56455300
13	5000	9200000	383300	10500	60200	0.0	3738900	0	3738900	60194200
14	5000	9200000	383300	10500	60200	0.0	3648500	0	3648500	63842700
15	5000	9200000	383300	10500	60200	0.0	3558200	0	3558200	67400900
16	3500	6440000	268300	7300	42100	0.0	3106100	0	3106100	70507000
17	3500	6440000	268300	7300	42100	0.0	3015800	0	3015800	73522800
18	3500	6440000	268300	7300	42100	0.0	2925400	0	2925400	76448200
19	3500	6440000	268300	7300	42100	0.0	2835100	0	2835100	79283300
20	3500	6440000	268300	7300	42100	0.0	2744700	0	2744700	82028000
21	1500	2760000	115000	3100	18000	0.0	2115700	0	2115700	84143700
22	1500	2760000	115000	3100	18000	0.0	2025400	0	2025400	86169100
23	1500	2760000	115000	3100	18000	0.0	1935000	0	1935000	88104100
24	1500	2760000	115000	3100	18000	0.0	1844700	0	1844700	89948800
25	1500	2760000	115000	3100	18000	0.0	1756300	0	1756300	91703100
26	1500	2760000	115000	3100	18000	0.0	1664000	0	1664000	93367100
27	1500	2760000	115000	3100	18000	0.0	1573600	0	1573600	94940700
28	1500	2760000	115000	3100	18000	0.0	1483300	0	1483300	96424000
29	1500	2760000	115000	3100	18000	0.0	1392900	0	1392900	97816900
30	1500	2760000	115000	3100	18000	0.0	1302500	0	1302500	99119400
TOT	127500	234600000	9775000	267000	1533500		99119400	0	99119400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.14	0.0	10.14	
MILLS PER KILOWATT-HOUR							3.89	0.0	3.89	
CENTS PER MILLION BTU HEAT INPUT							42.25	0.0	42.25	
DOLLARS PER TON OF SULFUR REMOVED							371.23	0.0	371.23	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							40142800	0	40142800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.54	0.0	9.54	
MILLS PER KILOWATT-HOUR							3.66	0.0	3.66	
CENTS PER MILLION BTU HEAT INPUT							39.76	0.0	39.76	
DOLLARS PER TON OF SULFUR REMOVED							348.76	0.0	348.76	

Table B-4. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Investment $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	271,000	4.1
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	528,000	8.0
Sulfur dioxide scrubbers and ducts (2 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	2,278,000	34.5
Stack gas reheat (2 direct oil fired reheaters)	142,000	2.1
Fans (2 fans including ducts and dampers between tie in to existing ducts and inlet to supplemental fan)	757,000	11.5
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	1,554,000	23.5
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	229,000	3.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	534,000	8.1
Construction facilities	315,000	4.8
Subtotal direct investment	6,608,000	100.0
Engineering design and supervision	793,000	12.0
Construction field expense	991,000	15.0
Contractor fees	595,000	9.0
Contingency	793,000	12.0
Subtotal fixed investment	9,780,000	148.0
Allowance for startup and modifications	782,000	11.8
Interest during construction (8%/annum rate)	782,000	11.8
Total capital investment	11,344,000	171.6

[a] Basis:

Stack gas reheat to 175 °F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 20 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-5. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	73.9 M tons	4.00/ton	295,600	7.64
Subtotal raw material			295,600	7.64
Conversion costs				
Operating labor and supervision	17,520 man hr	8.00/man hr	140,200	3.63
Utilities				
Fuel oil (No. 6)	1,720,000 gal	0.23/gal	395,600	10.23
Process water	105,700 M gal	0.08/M gal	8,500	0.22
Electricity	27,140,000 kWh	0.011/kWh	298,500	7.72
Maintenance				
Labor and material, .09 x 6,608,000			594,700	15.38
Analyses			24,000	0.62
Subtotal conversion costs			1,461,500	37.80
Subtotal direct costs			1,757,100	45.44
Indirect Costs				
Average capital charges at 15.9% of total capital investment			1,803,700	46.64
Overhead				
Plant, 20% of conversion costs			292,300	7.56
Administrative, 10% of operating labor			14,000	0.36
Subtotal indirect costs			2,110,000	54.56
Total annual operating cost			3,867,100	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	6.98	2.76	29.08	255.25

[a] Basis

Remaining life of power plant, 20 yr
Coal burned, 554,200 tons/yr, 9,500 Btu/kWh
Stack gas reheat to 175°F
Power unit on-stream time, 7,000 hr/yr
Midwest plant location, 1975 operating costs
Total capital investment, $11,344,000; subtotal direct investment, $6,608,000
Working capital, $294,900
Investment and operating cost for removal and disposal of fly ash excluded

Table B-6

LIMESTONE SLURRY PROCESS, 200 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 11344000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	395800	10800	62100	0.0	4554600	0	4554600	4554600
12	5000	9500000	395800	10800	62100	0.0	4436600	0	4436600	8991200
13	5000	9500000	395800	10800	62100	0.0	4318600	0	4318600	13309800
14	5000	9500000	395800	10800	62100	0.0	4200600	0	4200600	17510400
15	5000	9500000	395800	10800	62100	0.0	4082600	0	4082600	21593000
16	3500	6650000	277100	7600	43500	0.0	3577100	0	3577100	25170100
17	3500	6650000	277100	7600	43500	0.0	3459100	0	3459100	28629200
18	3500	6650000	277100	7600	43500	0.0	3341100	0	3341100	31970300
19	3500	6650000	277100	7600	43500	0.0	3223100	0	3223100	35193400
20	3500	6650000	277100	7600	43500	0.0	3105200	0	3105200	38298600
21	1500	2850000	118700	3200	18600	0.0	2421400	0	2421400	40720000
22	1500	2850000	118700	3200	18600	0.0	2303400	0	2303400	43023400
23	1500	2850000	118700	3200	18600	0.0	2185400	0	2185400	45208800
24	1500	2850000	118700	3200	18600	0.0	2067400	0	2067400	47276200
25	1500	2850000	118700	3200	18600	0.0	1949500	0	1949500	49225700
26	1500	2850000	118700	3200	18600	0.0	1831500	0	1831500	51057200
27	1500	2850000	118700	3200	18600	0.0	1713500	0	1713500	52770700
28	1500	2850000	118700	3200	18600	0.0	1595500	0	1595500	54366200
29	1500	2850000	118700	3200	18600	0.0	1477600	0	1477600	55643800
30	1500	2850000	118700	3200	18600	0.0	1359600	0	1359600	57203400
TOT	57500	109250000	4551500	124000	714000		57203400	0	57203400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							12.57	0.0	12.57	
MILLS PER KILOWATT-HOUR							4.97	0.0	4.97	
CENTS PER MILLION BTU HEAT INPUT							52.36	0.0	52.36	
DOLLARS PER TON OF SULFUR REMOVED							461.32	0.0	461.32	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							29067600	0	29067800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							11.94	0.0	11.94	
MILLS PER KILOWATT-HOUR							4.73	0.0	4.73	
CENTS PER MILLION BTU HEAT INPUT							49.76	0.0	49.76	
DOLLARS PER TON OF SULFUR REMOVED							437.77	0.0	437.77	

Table B-7. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	482,000	3.4
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	1,000,000	7.1
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	5,243,000	37.1
Stack gas reheat (4 direct oil-fired reheaters)	323,000	2.3
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,710,000	12.1
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	3,611,000	25.6
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	335,000	2.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	740,000	5.2
Construction facilities	672,000	4.8
Subtotal direct investment	14,116,000	100.0
Engineering design and supervision	1,412,000	10.0
Construction field expense	1,835,000	13.0
Contractor fees	988,000	7.0
Contingency	1,553,000	11.0
Subtotal fixed investment	19,904,000	141.0
Allowance for startup and modifications	1,592,000	11.3
Interest during construction (8%/annum rate)	1,592,000	11.3
Total capital investment	23,088,000	163.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-8. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating costs
Direct Costs				
Delivered raw material				
Limestone	178.9 M tons	4.00/ton	715,600	9.07
Subtotal raw material			715,600	9.07
Conversion costs				
Operating labor and supervision	26,280 man-hr	8.00/man-hr	210,200	2.66
Utilities				
Fuel oil (No. 6)	4,160,000 gal	0.23/gal	956,800	12.12
Process water	255,900 M gal	0.08/M gal	20,500	0.26
Electricity	65,720,000 kWh	0.010/kWh	657,200	8.33
Maintenance				
Labor and material, .08 x 14,116,000			1,129,300	14.31
Analyses			45,600	0.58
Subtotal conversion costs			3,019,600	38.26
Subtotal direct costs			3,735,200	47.33
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,532,500	44.75
Overhead				
Plant, 20% of conversion costs			603,900	7.65
Administrative, 10% of operating labor			21,000	0.27
Subtotal indirect costs			4,157,400	52.67
Total annual operating cost			7,892,600	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.88	2.26	24.51	215.17

[a] Basis:

Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $23,088,000; subtotal direct investment, $14,116,000.
Working capital, $628,200.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-9

LIMESTONE SLURRY PROCESS, 500 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 23088000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36700	210600	0.0	10293700	0	10293700	10293700
7	7000	32200000	1341700	36700	210600	0.0	10101600	0	10101600	20395300
8	7000	32200000	1341700	36700	210600	0.0	9909500	0	9909500	30304800
9	7000	32200000	1341700	36700	210600	0.0	9717400	0	9717400	40022200
10	7000	32200000	1341700	36700	210600	0.0	9525400	0	9525400	49547600
11	5000	23000000	958300	26200	150400	0.0	8262700	0	8262700	57810300
12	5000	23000000	958300	26200	150400	0.0	8070600	0	8070600	65880900
13	5000	23000000	958300	26200	150400	0.0	7878500	0	7878500	73759400
14	5000	23000000	958300	26200	150400	0.0	7686400	0	7686400	81445800
15	5000	23000000	958300	26200	150400	0.0	7494300	0	7494300	88940100
16	3500	16100000	670800	18300	105300	0.0	6465800	0	6465800	95405900
17	3500	16100000	670800	18300	105300	0.0	6273700	0	6273700	101679600
18	3500	16100000	670800	18300	105300	0.0	6081600	0	6081600	107761200
19	3500	16100000	670800	18300	105300	0.0	5889600	0	5889600	113650800
20	3500	16100000	670800	18300	105300	0.0	5697500	0	5697500	119348300
21	1500	6900000	287500	7900	45100	0.0	4301600	0	4301600	123650100
22	1500	6900000	287500	7900	45100	0.0	4109700	0	4109700	127759800
23	1500	6900000	287500	7900	45100	0.0	3917600	0	3917600	131677400
24	1500	6900000	287500	7900	45100	0.0	3725500	0	3725500	135402900
25	1500	6900000	287500	7900	45100	0.0	3533400	0	3533400	138936300
26	1500	6900000	287500	7900	45100	0.0	3341300	0	3341300	142277600
27	1500	6900000	287500	7900	45100	0.0	3149300	0	3149300	145426900
28	1500	6900000	287500	7900	45100	0.0	2957200	0	2957200	148384100
29	1500	6900000	287500	7900	45100	0.0	2765100	0	2765100	151149200
30	1500	6900000	287500	7900	45100	0.0	2573000	0	2573000	153722200
TOT	92500	425500000	17729000	485000	2782500		153722200	0	153722200	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							8.67	0.0	8.67	
MILLS PER KILOWATT-HOUR							3.32	0.0	3.32	
CENTS PER MILLION BTU HEAT INPUT							36.13	0.0	36.13	
DOLLARS PER TON OF SULFUR REMOVED							316.95	0.0	316.95	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							70550000	0	70550000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							8.07	0.0	8.07	
MILLS PER KILOWATT-HOUR							3.09	0.0	3.09	
CENTS PER MILLION BTU HEAT INPUT							33.61	0.0	33.61	
DOLLARS PER TON OF SULFUR REMOVED							295.06	0.0	295.06	

Table B-10. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	291,000	2.0
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	601,000	4.2
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	3,203,000	22.2
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	4,745,000	32.9
Stack gas reheat (4 indirect steam reheaters)	556,000	3.8
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	854,000	5.9
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	2,789,000	19.3
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	638,000	4.4
Construction facilities	687,000	4.8
Subtotal direct investment	14,431,000	100.0
Engineering design and supervision	1,299,000	9.0
Construction field expense	1,587,000	11.0
Contractor fees	722,000	5.0
Contingency	1,443,000	10.0
Subtotal fixed investment	19,482,000	135.0
Allowance for startup and modifications	1,559,000	10.8
Interest during construction (8%/annum rate)	1,559,000	10.8
Total capital investment	22,600,000	156.6

[a] Basis:
Stack gas reheat to 175°F by indirect steam reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-11. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	100.0 M tons	4.00/ton	400,000	5.90
Subtotal raw material			400,000	5.90
Conversion costs				
Operating labor and supervision	21,680 man-hr	8.00/man-hr	173,400	2.56
Utilities				
Steam	492,800 M lb	0.70/M lb	345,000	5.09
Process water	217,900 M gal	0.08/M gal	17,400	0.26
Electricity	76,060,000 kWh	0.010/kWh	760,600	11.23
Maintenance				
Labor and material, .08 x 14,431,000			1,154,500	17.04
Analyses			40,800	0.60
Subtotal conversion costs			2,491,700	36.78
Subtotal direct costs			2,891,700	42.68
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,367,400	49.70
Overhead				
Plant, 20% of conversion costs			498,300	7.36
Administrative, 10% of operating labor			17,300	0.26
Subtotal indirect costs			3,883,000	57.32
Total annual operating cost			6,774,700	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.16	1.94	21.51	330.47

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $22,600,000; subtotal direct investment, $14,431,000.
Working capital, $481,800.
Investment and operating cost for disposal of fly ash excluded.

Table B-12

LIMESTONE SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 2.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 22600000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	20500	117700	0.0	9125800	0	9125800	9125800
2	7000	31500000	1312500	20500	117700	0.0	8969100	0	8969100	18094900
3	7000	31500000	1312500	20500	117700	0.0	8812400	0	8812400	26907300
4	7000	31500000	1312500	20500	117700	0.0	8655700	0	8655700	35563000
5	7000	31500000	1312500	20500	117700	0.0	8499100	0	8499100	44062100
6	7000	31500000	1312500	20500	117700	0.0	8342400	0	8342400	52404500
7	7000	31500000	1312500	20500	117700	0.0	8185700	0	8185700	60590200
8	7000	31500000	1312500	20500	117700	0.0	8029000	0	8029000	68619200
9	7000	31500000	1312500	20500	117700	0.0	7872300	0	7872300	76491500
10	7000	31500000	1312500	20500	117700	0.0	7715600	0	7715600	84207100
11	5000	22500000	937500	14600	84100	0.0	6757600	0	6757600	90964700
12	5000	22500000	937500	14600	84100	0.0	6600900	0	6600900	97565600
13	5000	22500000	937500	14600	84100	0.0	6444300	0	6444300	104009900
14	5000	22500000	937500	14600	84100	0.0	6287600	0	6287600	110297500
15	5000	22500000	937500	14600	84100	0.0	6130900	0	6130900	116428400
16	3500	15750000	656200	10300	58900	0.0	5339900	0	5339900	121768300
17	3500	15750000	656200	10300	58900	0.0	5183200	0	5183200	126951500
18	3500	15750000	656200	10300	58900	0.0	5026500	0	5026500	131978000
19	3500	15750000	656200	10300	58900	0.0	4869800	0	4869800	136847800
20	3500	15750000	656200	10300	58900	0.0	4713200	0	4713200	141561000
21	1500	6750000	281200	4400	25200	0.0	3623700	0	3623700	145184700
22	1500	6750000	281200	4400	25200	0.0	3467000	0	3467000	148651700
23	1500	6750000	281200	4400	25200	0.0	3310300	0	3310300	151962000
24	1500	6750000	281200	4400	25200	0.0	3153600	0	3153600	155115600
25	1500	6750000	281200	4400	25200	0.0	2996900	0	2996900	158112500
26	1500	6750000	281200	4400	25200	0.0	2840200	0	2840200	160952700
27	1500	6750000	281200	4400	25200	0.0	2683600	0	2683600	163636300
28	1500	6750000	281200	4400	25200	0.0	2526900	0	2526900	166163200
29	1500	6750000	281200	4400	25200	0.0	2370200	0	2370200	168533400
30	1500	6750000	281200	4400	25200	0.0	2213500	0	2213500	170746900
TOT	127500	573750000	23905500	373500	2144000		170746900	0	170746900	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							7.14	0.0	7.14	
MILLS PER KILOWATT-HOUR							2.68	0.0	2.68	
CENTS PER MILLION BTU HEAT INPUT							29.76	0.0	29.76	
DOLLARS PER TON OF SULFUR REMOVED							457.15	0.0	457.15	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							69314200	0	69314200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							6.74	0.0	6.74	
MILLS PER KILOWATT-HOUR							2.53	0.0	2.53	
CENTS PER MILLION BTU HEAT INPUT							28.07	0.0	28.07	
DOLLARS PER TON OF SULFUR REMOVED							431.33	0.0	431.33	

Table B-13. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	419,000	2.6
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	899,000	5.6
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	3,203,000	19.9
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	4,745,000	29.5
Stack gas reheat (4 indirect steam reheaters)	556,000	3.5
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	854,000	5.3
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps pond, liner, and pond water return pumps)	3,923,000	24.4
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	638,000	4.0
Construction facilities	765,000	4.8
Subtotal direct investment	16,069,000	100.0
Engineering design and supervision	1,446,000	9.0
Construction field expense	1,768,000	11.0
Contractor fees	803,000	5.0
Contingency	1,607,000	10.0
Subtotal fixed investment	21,693,000	135.0
Allowance for startup and modifications	1,735,000	10.8
Interest during construction (8%/annum rate)	1,735,000	10.8
Total capital investment	25,163,000	156.6

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage, only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-14. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	175.0 M tons	4.00/ton	700,000	9.09
Subtotal raw material			700,000	9.09
Conversion costs				
Operating labor and supervision	26,280 man-hr	8.00/man-hr	210,200	2.73
Utilities				
Steam	492,800 M lb	0.70/M lb	345,000	4.48
Process water	250,300 M gal	0.08/M gal	20,000	0.26
Electricity	78,740,000 kWh	0.010/kWh	787,400	10.22
Maintenance				
Labor and material, .08 × 16,069,000			1,285,500	16.69
Analyses			45,600	0.59
Subtotal conversion costs			2,693,700	34.97
Subtotal direct costs			3,393,700	44.06
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,749,300	48.68
Overhead				
Plant, 20% of conversion costs			538,700	6.99
Administrative, 10% of operating labor			21,000	0.27
Subtotal indirect costs			4,309,000	55.94
Total annual operating cost			7,702,700	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.87	2.20	24.45	214.68

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $25,163,000; subtotal direct investment, $16,069,000.
Working capital, $572,600.
Investment and operating cost for disposal of fly ash excluded.

Table B-15

LIMESTONE SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT- $ 25163000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	35900	206000	0.0	10320500	0	10320500	10320500
2	7000	31500000	1312500	35900	206000	0.0	10146000	0	10146000	20466500
3	7000	31500000	1312500	35900	206000	0.0	9971600	0	9971600	30438100
4	7000	31500000	1312500	35900	206000	0.0	9797100	0	9797100	40235200
5	7000	31500000	1312500	35900	206000	0.0	9622600	0	9622600	49857800
6	7000	31500000	1312500	35900	206000	0.0	9448200	0	9448200	59306000
7	7000	31500000	1312500	35900	206000	0.0	9273700	0	9273700	68579700
8	7000	31500000	1312500	35900	206000	0.0	9099200	0	9099200	77678900
9	7000	31500000	1312500	35900	206000	0.0	8924700	0	8924700	86603600
10	7000	31500000	1312500	35900	206000	0.0	8750300	0	8750300	95353900
11	5000	22500000	937500	25600	147100	0.0	7640900	0	7640900	102994800
12	5000	22500000	937500	25600	147100	0.0	7466400	0	7466400	110461200
13	5000	22500000	937500	25600	147100	0.0	7292000	0	7292000	117753200
14	5000	22500000	937500	25600	147100	0.0	7117500	0	7117500	124870700
15	5000	22500000	937500	25600	147100	0.0	6943000	0	6943000	131813700
16	3500	15750000	656200	17900	103000	0.0	6029900	0	6029900	137843600
17	3500	15750000	656200	17900	103000	0.0	5855500	0	5855500	143699100
18	3500	15750000	656200	17900	103000	0.0	5681000	0	5681000	149380100
19	3500	15750000	656200	17900	103000	0.0	5506500	0	5506500	154886600
20	3500	15750000	656200	17900	103000	0.0	5332100	0	5332100	160218700
21	1500	6750000	281200	7700	44100	0.0	4074300	0	4074300	164293000
22	1500	6750000	281200	7700	44100	0.0	3899800	0	3899800	168192800
23	1500	6750000	281200	7700	44100	0.0	3725400	0	3725400	171918200
24	1500	6750000	281200	7700	44100	0.0	3550900	0	3550900	175469100
25	1500	6750000	281200	7700	44100	0.0	3376600	0	3376600	178845500
26	1500	6750000	281200	7700	44100	0.0	3201900	0	3201900	182047400
27	1500	6750000	281200	7700	44100	0.0	3027500	0	3027500	185074900
28	1500	6750000	281200	7700	44100	0.0	2853000	0	2853000	187927900
29	1500	6750000	281200	7700	44100	0.0	2678500	0	2678500	190606400
30	1500	6750000	281200	7700	44100	0.0	2506100	0	2506100	193110500
TOT	127500	573750000	23905500	653500	3751500		193110500	0	193110500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	8.08	0.0	8.08
MILLS PER KILOWATT-HOUR	3.03	0.0	3.03
CENTS PER MILLION BTU HEAT INPUT	33.66	0.0	33.66
DOLLARS PER TON OF SULFUR REMOVED	295.50	0.0	295.50
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	78439900	0	78439900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	7.63	0.0	7.63
MILLS PER KILOWATT-HOUR	2.86	0.0	2.86
CENTS PER MILLION BTU HEAT INPUT	31.77	0.0	31.77
DOLLARS PER TON OF SULFUR REMOVED	276.85	0.0	276.85

Table B-16. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit. 5.0% S in fuel. 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	528,000	3.0
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	1,162,000	6.7
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	3,203,000	18.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	4,745,000	27.2
Stack gas reheat (4 indirect steam reheaters)	556,000	3.2
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	854,000	4.9
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	4,876,000	27.9
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	638,000	3.6
Construction facilities	831,000	4.8
Subtotal direct investment	17,460,000	100.0
Engineering design and supervision	1,571,000	9.0
Construction field expense	1,921,000	11.0
Contractor fees	873,000	5.0
Contingency	1,746,000	10.0
Subtotal fixed investment	23,571,000	135.0
Allowance for startup and modifications	1,886,000	10.8
Interest during construction (8%/annum rate)	1,886,000	10.8
Total capital investment	27,343,000	156.6

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-17. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 5.0% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	250.0 M tons	4.00/ton	1,000,000	11.73
Subtotal raw material			1,000,000	11.73
Conversion costs				
Operating labor and supervision	28,360 man-hr	8.00/man-hr	226,900	2.66
Utilities				
Steam	492,800 M lb	0.70/M lb	345,000	4.05
Process water	282,700 M gal	0.08/M gal	22,600	0.27
Electricity	81,400,000 kWh	0.010/kWh	814,000	9.55
Maintenance				
Labor and material, .08 × 17,460,000			1,396,800	16.39
Analyses			49,200	0.58
Subtotal conversion costs			2,854,500	33.50
Subtotal direct costs			3,854,500	45.23
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,074,100	47.80
Overhead				
Plant, 20% of conversion costs			570,900	6.70
Administrative, 10% of operating labor			22,700	0.27
Subtotal indirect costs			4,667,700	54.77
Total annual operating cost			8,522,200	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	6.49	2.43	27.05	166.25

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $27,343,000; subtotal direct investment, $17,460,000.
Working capital, $656,500.
Investment and operating cost for disposal of fly ash excluded.

Table B-18

LIMESTONE SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 5.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 27343000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	51300	294300	0.0	11366700	0	11366700	11366700
2	7000	31500000	1312500	51300	294300	0.0	11177200	0	11177200	22543900
3	7000	31500000	1312500	51300	294300	0.0	10987600	0	10987600	33531500
4	7000	31500000	1312500	51300	294300	0.0	10798000	0	10798000	44329500
5	7000	31500000	1312500	51300	294300	0.0	10608500	0	10608500	54938000
6	7000	31500000	1312500	51300	294300	0.0	10418900	0	10418900	65356900
7	7000	31500000	1312500	51300	294300	0.0	10229300	0	10229300	75586200
8	7000	31500000	1312500	51300	294300	0.0	10039700	0	10039700	85625900
9	7000	31500000	1312500	51300	294300	0.0	9850200	0	9850200	95476100
10	7000	31500000	1312500	51300	294300	0.0	9660600	0	9660600	105136700
11	5000	22500000	937500	36600	210200	0.0	8411000	0	8411000	113547700
12	5000	22500000	937500	36600	210200	0.0	8221500	0	8221500	121769200
13	5000	22500000	937500	36600	210200	0.0	8031900	0	8031900	129801100
14	5000	22500000	937500	36600	210200	0.0	7842300	0	7842300	137643400
15	5000	22500000	937500	36600	210200	0.0	7652700	0	7652700	145296100
16	3500	15750000	656200	25600	147100	0.0	6627900	0	6627900	151924000
17	3500	15750000	656200	25600	147100	0.0	6436300	0	6436300	158362300
18	3500	15750000	656200	25600	147100	0.0	6248700	0	6248700	164611000
19	3500	15750000	656200	25600	147100	0.0	6059200	0	6059200	170670200
20	3500	15750000	656200	25600	147100	0.0	5869600	0	5869600	176539800
21	1500	6750000	281200	11000	63100	0.0	4459500	0	4459500	180999300
22	1500	6750000	281200	11000	63100	0.0	4269900	0	4269900	185269200
23	1500	6750000	281200	11000	63100	0.0	4080400	0	4080400	189349600
24	1500	6750000	281200	11000	63100	0.0	3890800	0	3890800	193240400
25	1500	6750000	281200	11000	63100	0.0	3701200	0	3701200	196941600
26	1500	6750000	281200	11000	63100	0.0	3511700	0	3511700	200453300
27	1500	6750000	281200	11000	63100	0.0	3322100	0	3322100	203775400
28	1500	6750000	281200	11000	63100	0.0	3132500	0	3132500	206907900
29	1500	6750000	281200	11000	63100	0.0	2943000	0	2943000	209850900
30	1500	6750000	281200	11000	63100	0.0	2753600	0	2753600	212604300
TOT	127500	573750000	23905500	934000	5360500		212604300	0	212604300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							8.89	0.0	8.89	
MILLS PER KILOWATT-HOUR							3.33	0.0	3.33	
CENTS PER MILLION BTU HEAT INPUT							37.06	0.0	37.06	
DOLLARS PER TON OF SULFUR REMOVED							227.63	0.0	227.63	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							86426800	0	86426800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							8.40	0.0	8.40	
MILLS PER KILOWATT-HOUR							3.15	0.0	3.15	
CENTS PER MILLION BTU HEAT INPUT							35.01	0.0	35.01	
DOLLARS PER TON OF SULFUR REMOVED							214.99	0.0	214.99	

Table B-19. Limestone Slurry Process Summary of Estimated Fixed Investment[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	745,000	3.4
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	1,621,000	7.4
Sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	8,530,000	38.9
Stack gas reheat (4 direct oil-fired reheaters)	559,000	2.5
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	2,611,000	11.9
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	5,440,000	24.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	448,000	2.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	948,000	4.3
Construction facilities	1,045,000	4.8
Subtotal direct investment	21,947,000	100.0
Engineering design and supervision	1,975,000	9.0
Construction field expense	2,634,000	12.0
Contractor fees	1,536,000	7.0
Contingency	2,195,000	10.0
Subtotal fixed investment	30,287,000	138.0
Allowance for startup and modifications	2,423,000	11.0
Interest during construction (8%/annum rate)	2,423,000	11.0
Total capital investment	35,133,000	160.0

[a] Basis:

Stack gas reheat to 175° F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-20. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	350.0 M tons	4.00/ton	1,400,000	10.98
Subtotal raw material			1,400,000	10.98
Conversion costs				
Operating labor and supervision	35,040man-hr	8.00/man-hr	280,300	2.20
Utilities				
Fuel oil (No. 6)	8,130,000 gal	0.23/gal	1,869,900	14.67
Process water	500,600 M gal	0.08/M gal	40,000	0.31
Electricity	128,570,000 kWh	0.009/kWh	1,157,100	9.07
Maintenance				
Labor and material, .07 x 21,947,000			1,536,300	12.05
Analyses			74,400	0.58
Subtotal conversion costs			4,958,000	38.88
Subtotal direct costs			6,358,000	49.86
Indirect Costs				
Average capital charges at 15.3% of total capital investment			5,375,300	42.14
Overhead				
Plant, 20% of conversion costs			991,600	7.78
Administrative, 10% of operating labor			28,000	0.22
Subtotal indirect costs			6,394,900	50.14
Total annual operating cost			12,752,900	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	4.86	1.82	20.24	177.72

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 2,625,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $35,133,000; subtotal direct investment, $21,947,000.
Working capital, $1,073,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-21

LIMESTONE SLURRY PROCESS, 1000 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 35133000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	2625000	71800	412000	0.0	16406800	0	16406800	16406800
7	7000	63000000	2625000	71800	412000	0.0	16114500	0	16114500	32521300
8	7000	63000000	2625000	71800	412000	0.0	15822200	0	15822200	48343500
9	7000	63000000	2625000	71800	412000	0.0	15529900	0	15529900	63873400
10	7000	63000000	2625000	71800	412000	0.0	15237600	0	15237600	79111000
11	5000	45000000	1875000	51300	294300	0.0	13074700	0	13074700	92185700
12	5000	45000000	1875000	51300	294300	0.0	12782300	0	12782300	104968000
13	5000	45000000	1875000	51300	294300	0.0	12490000	0	12490000	117458000
14	5000	45000000	1875000	51300	294300	0.0	12197700	0	12197700	129655700
15	5000	45000000	1875000	51300	294300	0.0	11905400	0	11905400	141561100
16	3500	31500000	1312500	35900	206000	0.0	10165000	0	10165000	151726100
17	3500	31500000	1312500	35900	206000	0.0	9872700	0	9872700	161598800
18	3500	31500000	1312500	35900	206000	0.0	9580400	0	9580400	171179200
19	3500	31500000	1312500	35900	206000	0.0	9288100	0	9288100	180467300
20	3500	31500000	1312500	35900	206000	0.0	8995800	0	8995800	189463100
21	1500	13500000	562500	15400	88300	0.0	6652700	0	6652700	196115800
22	1500	13500000	562500	15400	88300	0.0	6360400	0	6360400	202476200
23	1500	13500000	562500	15400	88300	0.0	6068100	0	6068100	208544300
24	1500	13500000	562500	15400	88300	0.0	5775800	0	5775800	214320100
25	1500	13500000	562500	15400	88300	0.0	5483500	0	5483500	219803600
26	1500	13500000	562500	15400	88300	0.0	5191200	0	5191200	224994800
27	1500	13500000	562500	15400	88300	0.0	4898900	0	4898900	229893700
28	1500	13500000	562500	15400	88300	0.0	4606600	0	4606600	234500300
29	1500	13500000	562500	15400	88300	0.0	4314300	0	4314300	238814600
30	1500	13500000	562500	15400	88300	0.0	4022000	0	4022000	242836600
TOT	92500	832500000	34687500	949000	5444500		242836600	0	242836600	

	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	7.00	0.0	7.00
MILLS PER KILOWATT-HOUR	2.63	0.0	2.63
CENTS PER MILLION BTU HEAT INPUT	29.17	0.0	29.17
DOLLARS PER TON OF SULFUR REMOVED	255.89	0.0	255.89
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	111985400	0	111985400
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	6.55	0.0	6.55
MILLS PER KILOWATT-HOUR	2.45	0.0	2.45
CENTS PER MILLION BTU HEAT INPUT	27.27	0.0	27.27
DOLLARS PER TON OF SULFUR REMOVED	239.29	0.0	239.29

Table B-22. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	643,000	2.6
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	1,445,000	5.9
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	4,756,000	19.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	7,616,000	30.9
Stack gas reheat (4 indirect steam reheaters)	942,000	3.8
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	1,294,000	5.2
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	5,865,000	23.8
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	89,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	814,000	3.3
Construction facilities	1,173,000	4.8
Subtotal direct investment	24,637,000	100.0
Engineering design and supervision	1,971,000	8.0
Construction field expense	2,464,000	10.0
Contractor fees	1,232,000	5.0
Contingency	2,217,000	9.0
Subtotal fixed investment	32,521,000	132.0
Allowance for startup and modifications	2,602,000	10.6
Interest during construction (8%/annum rate)	2,602,000	10.6
Total capital investment	37,725,000	153.2

[a] Basis:
Stack gas reheat to 175 °F by indirect steam reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-23. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	338.4 M tons	4.00/ton	1,353,600	11.40
Subtotal raw material			1,353,600	11.40
Conversion costs				
Operating labor and supervision	35,040 man-hr	8.00/man-hr	280,300	2.36
Utilities				
Steam	952,700 M lb	0.60/M lb	571,600	4.81
Process water	484,000 M gal	0.08/M gal	38,700	0.33
Electricity	152,220,000 kWh	0.009/kWh	1,370,000	11.54
Maintenance				
Labor and material, .07 x 24,637,000			1,724,600	14.52
Analyses			74,400	0.63
Subtotal conversion costs			4,059,600	34.19
Subtotal direct costs			5,413,200	45.59
Indirect Costs				
Average capital charges at 14.9% of total capital investment			5,621,000	47.33
Overhead				
Plant, 20% of conversion costs			811,900	6.84
Administrative, 10% of operating labor			28,000	0.24
Subtotal indirect costs			6,460,900	54.41
Total annual operating cost			11,874,100	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	4.68	1.70	19.50	171.17

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $37,725,000; subtotal direct investment, $24,637,000.
Working capital, $919,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-24

LIMESTONE SLURRY PROCESS, 1000 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 37725000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2537500	69400	398300	0.0	15798800	0	15798800	15798800
2	7000	60900000	2537500	69400	398300	0.0	15537200	0	15537200	31336000
3	7000	60900000	2537500	69400	398300	0.0	15275700	0	15275700	46611700
4	7000	60900000	2537500	69400	398300	0.0	15014100	0	15014100	61625800
5	7000	60900000	2537500	69400	398300	0.0	14752600	0	14752600	76378400
6	7000	60900000	2537500	69400	398300	0.0	14491000	0	14491000	90869400
7	7000	60900000	2537500	69400	398300	0.0	14229400	0	14229400	105098800
8	7000	60900000	2537500	69400	398300	0.0	13967900	0	13967900	119066700
9	7000	60900000	2537500	69400	398300	0.0	13706300	0	13706300	132773000
10	7000	60900000	2537500	69400	398300	0.0	13444800	0	13444800	146217800
11	5000	43500000	1812500	49600	284500	0.0	11657400	0	11657400	157875200
12	5000	43500000	1812500	49600	284500	0.0	11395800	0	11395800	169271000
13	5000	43500000	1812500	49600	284500	0.0	11134300	0	11134300	180405300
14	5000	43500000	1812500	49600	284500	0.0	10872700	0	10872700	191278000
15	5000	43500000	1812500	49600	284500	0.0	10611200	0	10611200	201889200
16	3500	30450000	1268700	34700	199100	0.0	9155000	0	9155000	211044200
17	3500	30450000	1268700	34700	199100	0.0	8893400	0	8893400	219937600
18	3500	30450000	1268700	34700	199100	0.0	8631900	0	8631900	228569500
19	3500	30450000	1268700	34700	199100	0.0	8370300	0	8370300	236939800
20	3500	30450000	1268700	34700	199100	0.0	8108800	0	8108800	245048600
21	1500	13050000	543700	14900	85300	0.0	6123000	0	6123000	251171600
22	1500	13050000	543700	14900	85300	0.0	5861400	0	5861400	257033000
23	1500	13050000	543700	14900	85300	0.0	5599900	0	5599900	262632900
24	1500	13050000	543700	14900	85300	0.0	5338300	0	5338300	267971200
25	1500	13050000	543700	14900	85300	0.0	5076800	0	5076800	273048000
26	1500	13050000	543700	14900	85300	0.0	4815200	0	4815200	277863200
27	1500	13050000	543700	14900	85300	0.0	4553600	0	4553600	282416800
28	1500	13050000	543700	14900	85300	0.0	4292100	0	4292100	286708900
29	1500	13050000	543700	14900	85300	0.0	4030500	0	4030500	290739400
30	1500	13050000	543700	14900	85300	0.0	3769000	0	3769000	294508400
TOT	127500	1109250000	46218000	1264500	7254000		294508400	0	294508400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							6.37	0.0	6.37	
MILLS PER KILOWATT-HOUR							2.31	0.0	2.31	
CENTS PER MILLION BTU HEAT INPUT							26.55	0.0	26.55	
DOLLARS PER TON OF SULFUR REMOVED							232.91	0.0	232.91	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							120015500	0	120015500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							6.03	0.0	6.03	
MILLS PER KILOWATT-HOUR							2.19	0.0	2.19	
CENTS PER MILLION BTU HEAT INPUT							25.14	0.0	25.14	
DOLLARS PER TON OF SULFUR REMOVED							220.62	0.0	220.62	

Table B-25. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	419,000	2.7
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	899,000	5.8
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	3,203,000	20.7
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	4,351,000	28.1
Stack gas reheat (4 indirect steam reheaters)	556,000	3.6
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	797,000	5.1
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	3,827,000	24.7
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	638,000	4.1
Construction facilities	738,000	4.8
Subtotal direct investment	15,495,000	100.0
Engineering design and supervision	1,395,000	9.0
Construction field expense	1,704,000	11.0
Contractor fees	775,000	5.0
Contingency	1,550,000	10.0
Subtotal fixed investment	20,919,000	135.0
Allowance for startup and modifications	1,674,000	10.8
Interest during construction (8%/annum rate)	1,674,000	10.8
Total capital investment	24,267,000	156.6

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-26. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	175.0 M tons	4.00/ton	700,000	9.48
Subtotal raw material			700,000	9.48
Conversion costs				
Operating labor and supervision	26,280 man-hr	8.00/man-hr	210,200	2.85
Utilities				
Steam	492,800 M lb	0.70/M lb	345,000	4.68
Process water	248,600 M gal	0.08/gal	19,900	0.27
Electricity	67,380,000 kWh	0.010/kWh	673,800	9.13
Maintenance				
Labor and material, .08 x 15,495,000			1,239,600	16.80
Analyses			45,600	0.62
Subtotal conversion costs			2,534,100	34.35
Subtotal direct costs			3,234,100	43.83
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,616,100	49.02
Overhead				
Plant, 20% of conversion costs			506,800	6.87
Administrative, 10% of operating labor			21,000	0.28
Subtotal indirect costs			4,143,900	56.17
Total annual operating cost			7,378,000	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.62	2.11	23.42	231.36

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $24,267,000; subtotal direct investment, $15,495,000.
Working capital, $546,800.
Investment and operating cost for disposal of fly ash excluded.

Table B-27

LIMESTONE SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 80% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 24269000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	31900	183100	0.0	9902900	0	9902900	9902900
2	7000	31500000	1312500	31900	183100	0.0	9734600	0	9734600	19637500
3	7000	31500000	1312500	31900	183100	0.0	9566300	0	9566300	29203800
4	7000	31500000	1312500	31900	183100	0.0	9398000	0	9398000	38601800
5	7000	31500000	1312500	31900	183100	0.0	9229800	0	9229800	47831600
6	7000	31500000	1312500	31900	183100	0.0	9061500	0	9061500	56893100
7	7000	31500000	1312500	31900	183100	0.0	8893200	0	8893200	65786300
8	7000	31500000	1312500	31900	183100	0.0	8724900	0	8724900	74511200
9	7000	31500000	1312500	31900	183100	0.0	8556700	0	8556700	83067900
10	7000	31500000	1312500	31900	183100	0.0	8388600	0	8388600	91656300
11	5000	22500000	937500	22800	130800	0.0	7334300	0	7334300	98790600
12	5000	22500000	937500	22800	130800	0.0	7166100	0	7166100	105956700
13	5000	22500000	937500	22800	130800	0.0	6997800	0	6997800	112954500
14	5000	22500000	937500	22800	130800	0.0	6829500	0	6829500	119784000
15	5000	22500000	937500	22800	130800	0.0	6661200	0	6661200	126445200
16	3500	15750000	656200	15900	91600	0.0	5792100	0	5792100	132237300
17	3500	15750000	656200	15900	91600	0.0	5623800	0	5623800	137861100
18	3500	15750000	656200	15900	91600	0.0	5455500	0	5455500	143316600
19	3500	15750000	656200	15900	91600	0.0	5287300	0	5287300	148603900
20	3500	15750000	656200	15900	91600	0.0	5119000	0	5119000	153722900
21	1500	6750000	281200	6800	39200	0.0	3921000	0	3921000	157643900
22	1500	6750000	281200	6800	39200	0.0	3752700	0	3752700	161396600
23	1500	6750000	281200	6800	39200	0.0	3584500	0	3584500	164981100
24	1500	6750000	281200	6800	39200	0.0	3416200	0	3416200	168397300
25	1500	6750000	281200	6800	39200	0.0	3267900	0	3267900	171665200
26	1500	6750000	281200	6800	39200	0.0	3079700	0	3079700	174724900
27	1500	6750000	281200	6800	39200	0.0	2911400	0	2911400	177636300
28	1500	6750000	281200	6800	39200	0.0	2743100	0	2743100	180379400
29	1500	6750000	281200	6800	39200	0.0	2574800	0	2574800	182954200
30	1500	6750000	281200	6800	39200	0.0	2406600	0	2406600	185360800
TOT	127500	573750000	23505500	580500	3335000		185360800	0	185360800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	7.75	0.0	7.75
MILLS PER KILOWATT-HOUR	2.91	0.0	2.91
CENTS PER MILLION BTU HEAT INPUT	32.31	0.0	32.31
DOLLARS PER TON OF SULFUR REMOVED	319.31	0.0	319.31
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	75259300	0	75259300
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	7.32	0.0	7.32
MILLS PER KILOWATT-HOUR	2.74	0.0	2.74
CENTS PER MILLION BTU HEAT INPUT	30.48	0.0	30.48
DOLLARS PER TON OF SULFUR REMOVED	301.04	0.0	301.04

Table B-28. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; off-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	419,000	3.2
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	899,000	6.9
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, and pumps)	3,203,000	24.4
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts to inlet of fan)	4,745,000	36.2
Stack gas reheat (4 indirect steam reheaters)	556,000	4.2
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	854,000	6.5
Calcium solids disposal (off-site disposal facilities including feed tank, agitator, pumps, thickener, drum filters, and cake loading silo)	1,106,000	8.4
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	638,000	4.9
Construction facilities	624,000	4.8
Subtotal direct investment	13,111,000	100.0
Engineering design and supervision	1,180,000	9.0
Construction field expense	1,442,000	11.0
Contractor fees	656,000	5.0
Contingency	1,311,000	10.0
Subtotal fixed investment	17,700,000	135.0
Allowance for startup and modifications	1,416,000	10.8
Interest during construction (8%/annum rate)	1,416,000	10.8
Total capital investment	20,532,000	156.6

[a] Basis:
Stack gas reheat to 175 °F by indirect steam reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-29. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; off-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	175.0 M tons	4.00/ton	700,000	8.36
Subtotal raw material			700,000	8.36
Conversion costs				
Operating labor and supervision	26,280 man-hr	8.00/man-hr	210,200	2.51
Utilities				
Steam	492,800 M lb	0.70/M lb	345,000	4.12
Process water	224,300 M gal	0.08/M gal	17,900	0.21
Electricity	78,920,000 kWh	0.010/kWh	789,200	9.42
Maintenance				
Labor and materials, .08 x 13,111,000			1,048,900	12.53
Analyses			45,600	0.54
Subtotal conversion costs			2,456,800	29.33
Subtotal direct costs			3,156,800	37.69
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,059,300	36.52
Overhead				
Plant, 20% of conversion costs			491,400	5.87
Administrative, 10% of operating labor			21,000	0.25
Subtotal indirect costs			3,571,700	42.64
Total annual operating cost excluding trucking and off-site disposal of calcium solids			6,728,500	80.33
Annual cost for trucking and off-site disposal of calcium solids at $4/ton			1,648,000	19.67
Total annual operating cost			8,376,500	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	6.38	2.39	26.59	233.46

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $20,532,000; subtotal direct investment, $13,111,000.
Solids disposed, 206,000 tons/yr calcium solids including hydrate water.
206,000 tons/yr associated water
412,000 tons/yr
Working capital, $534,300.
Investment and operating cost for disposal of fly ash excluded.

Table B-30

LIMESTONE SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL.

FIXED INVESTMENT: $ 20532000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	35900	412000	0.0	10512500	0	10512500	10512500
2	7000	31500000	1312500	35900	412000	0.0	10370100	0	10370100	20882600
3	7000	31500000	1312500	35900	412000	0.0	10227700	0	10227700	31110300
4	7000	31500000	1312500	35900	412000	0.0	10085400	0	10085400	41195700
5	7000	31500000	1312500	35900	412000	0.0	9943000	0	9943000	51138700
6	7000	31500000	1312500	35900	412000	0.0	9800700	0	9800700	60939400
7	7000	31500000	1312500	35900	412000	0.0	9658300	0	9658300	70597700
8	7000	31500000	1312500	35900	412000	0.0	9516000	0	9516000	80113700
9	7000	31500000	1312500	35900	412000	0.0	9373600	0	9373600	89487300
10	7000	31500000	1312500	35900	412000	0.0	9231300	0	9231300	98718600
11	5000	22500000	937500	25600	294300	0.0	7735000	0	7735000	106453600
12	5000	22500000	937500	25600	294300	0.0	7592600	0	7592600	114046200
13	5000	22500000	937500	25600	294300	0.0	7450300	0	7450300	121496500
14	5000	22500000	937500	25600	294300	0.0	7307900	0	7307900	128804400
15	5000	22500000	937500	25600	294300	0.0	7165600	0	7165600	135970000
16	3500	15750000	656200	17900	206000	0.0	5976300	0	5976300	141946300
17	3500	15750000	656200	17900	206000	0.0	5834000	0	5834000	147780300
18	3500	15750000	656200	17900	206000	0.0	5691600	0	5691600	153471900
19	3500	15750000	656200	17900	206000	0.0	5549300	0	5549300	159021200
20	3500	15750000	656200	17900	206000	0.0	5606900	0	5606900	164628100
21	1500	6750000	281200	7700	88300	0.0	3785100	0	3785100	168213200
22	1500	6750000	281200	7700	88300	0.0	3642700	0	3642700	171855900
23	1500	6750000	281200	7700	88300	0.0	3500300	0	3500300	175356200
24	1500	6750000	281200	7700	88300	0.0	3358000	0	3358000	178714200
25	1500	6750000	281200	7700	88300	0.0	3215600	0	3215600	181929800
26	1500	6750000	281200	7700	88300	0.0	3073300	0	3073300	185003100
27	1500	6750000	281200	7700	88300	0.0	2930900	0	2930900	187934000
28	1500	6750000	281200	7700	88300	0.0	2788600	0	2788600	190722600
29	1500	6750000	281200	7700	88300	0.0	2646200	0	2646200	193368800
30	1500	6750000	281200	7700	88300	0.0	2503900	0	2503900	195872700
TOT	127500	573750000	23905500	653500	7504500		195872700	0	195872700	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							8.19	0.0	8.19	
MILLS PER KILOWATT-HOUR							3.07	0.0	3.07	
CENTS PER MILLION BTU HEAT INPUT							34.14	0.0	34.14	
DOLLARS PER TON OF SULFUR REMOVED							299.73	0.0	299.73	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							80426200	0	80426200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							7.82	0.0	7.82	
MILLS PER KILOWATT-HOUR							2.93	0.0	2.93	
CENTS PER MILLION BTU HEAT INPUT							32.57	0.0	32.57	
DOLLARS PER TON OF SULFUR REMOVED							285.91	0.0	285.91	

Table B-31. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal; particulate scrubber required for fly ash removal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	482,000	2.6
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	1,000,000	5.4
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and all ductwork between outlet of supplemental fan and particulate scrubber)	3,977,000	21.7
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, effluent hold tanks, agitators, pumps, and exhaust gas ducts between SO_2 scrubber and stack gas plenum)	5,260,000	28.7
Stack gas reheat (4 direct oil-fired reheaters)	323,000	1.8
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet of supplemental fan)	1,738,000	9.5
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	3,611,000	19.7
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from the power plant)	335,000	1.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	740,000	4.0
Construction facilities	873,000	4.8
Subtotal direct investment	18,339,000	100.0
Engineering design and supervision	1,834,000	10.0
Construction field expense	2,384,000	13.0
Contractor fees	1,284,000	7.0
Contingency	2,017,000	11.0
Subtotal fixed investment	25,858,000	141.0
Allowance for startup and modifications	2,069,000	11.3
Interest during construction (8%/annum rate)	2,069,000	11.3
Total capital investment	29,996,000	163.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-32. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal; particulate scrubber required for fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	178.9 M tons	4.00/ton	715,600	7.48
Subtotal raw material			715,600	7.48
Conversion costs				
Operating labor and supervision	26,280 man-hr	8.00/man-hr	210,200	2.20
Utilities				
Fuel oil (No. 6)	4,160,000 gal	0.23/gal	956,300	9.99
Process water	255,900 M gal	0.08/M gal	20,500	0.21
Electricity	83,930,000 kWh	0.010/kWh	839,300	8.77
Maintenance				
Labor and material, .08 x 18,339,000			1,467,100	15.32
Analyses			45,600	0.48
Subtotal conversion costs			3,539,500	36.97
Subtotal direct costs			4,255,100	44.45
Indirect Costs				
Average capital charges at 15.3% of total capital investment			4,589,400	47.94
Overhead				
Plant, 20% of conversion costs			707,900	7.39
Administrative, 10% of operating labor			21,000	0.22
Subtotal indirect costs			5,318,300	55.55
Total annual operating cost			9,573,400	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	7.14	2.74	29.73	261.00

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $29,996,000; subtotal direct investment, $18,339,000.
Working capital, $712,200.
Investment and operating cost for disposal of fly ash excluded.

Table B-33

LIMESTONE SLURRY PROCESS, 500 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, FLYASH REMOVED BY PART. SCRUB.

FIXED INVESTMENT: $ 29996000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/ KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36700	210600	0.0	12693000	0	12693000	12693000
7	7000	32200000	1341700	36700	210600	0.0	12443400	0	12443400	25136400
8	7000	32200000	1341700	36700	210600	0.0	12193900	0	12193900	37330300
9	7000	32200000	1341700	36700	210600	0.0	11944300	0	11944300	49274600
10	7000	32200000	1341700	36700	210600	0.0	11694700	0	11694700	60969300
11	5000	23000000	958300	26200	150400	0.0	10238100	0	10238100	71207400
12	5000	23000000	958300	26200	150400	0.0	9988500	0	9988500	81195900
13	5000	23000000	958300	26200	150400	0.0	9739000	0	9739000	90934900
14	5000	23000000	958300	26200	150400	0.0	9489400	0	9489400	100424300
15	5000	23000000	958300	26200	150400	0.0	9239800	0	9239800	109664100
16	3500	16100000	670800	18300	105300	0.0	8043300	0	8043300	117707400
17	3500	16100000	670800	18300	105300	0.0	7793700	0	7793700	125501100
18	3500	16100000	670800	18300	105300	0.0	7544200	0	7544200	133045300
19	3500	16100000	670800	18300	105300	0.0	7294600	0	7294600	140339900
20	3500	16100000	670800	18300	105300	0.0	7045100	0	7045100	147385000
21	1500	6900000	287500	7900	45100	0.0	5422900	0	5422900	152807900
22	1500	6900000	287500	7900	45100	0.0	5173300	0	5173300	157981200
23	1500	6900000	287500	7900	45100	0.0	4923800	0	4923800	162905000
24	1500	6900000	287500	7900	45100	0.0	4674200	0	4674200	167579200
25	1500	6900000	287500	7900	45100	0.0	4424700	0	4424700	172003900
26	1500	6900000	287500	7900	45100	0.0	4175100	0	4175100	176179000
27	1500	6900000	287500	7900	45100	0.0	3925500	0	3925500	180104500
28	1500	6900000	287500	7900	45100	0.0	3676000	0	3676000	183780500
29	1500	6900000	287500	7900	45100	0.0	3426400	0	3426400	187206900
30	1500	6900000	287500	7900	45100	0.0	3176900	0	3176900	190383800
TOT	92500	425500000	17729000	485000	2782500		190383800	0	190383800	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.74	0.0	10.74	
MILLS PER KILOWATT-HOUR							4.12	0.0	4.12	
CENTS PER MILLION BTU HEAT INPUT							44.74	0.0	44.74	
DOLLARS PER TON OF SULFUR REMOVED							392.54	0.0	392.54	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							87143300	0	87143300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.96	0.0	9.96	
MILLS PER KILOWATT-HOUR							3.82	0.0	3.82	
CENTS PER MILLION BTU HEAT INPUT							41.52	0.0	41.52	
DOLLARS PER TON OF SULFUR REMOVED							364.46	0.0	364.46	

Table B-34. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(200-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	157,000	3.1
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	300,000	6.0
Sulfur dioxide scrubbers and ducts (2 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between common feed plenum and inlet of fan)	1,827,000	36.4
Stack gas reheat (2 direct oil-fired reheaters)	110,000	2.2
Fans (2 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	256,000	5.1
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	1,550,000	30.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	126,000	2.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	451,000	9.0
Construction facilities	239,000	4.8
Subtotal direct investment	5,016,000	100.0
Engineering design and supervision	552,000	11.0
Construction field expense	652,000	13.0
Contractor fees	351,000	7.0
Contingency	552,000	11.0
Subtotal fixed investment	7,123,000	142.0
Allowance for startup and modifications	570,000	11.4
Interest during construction (8%/annum rate)	570,000	11.4
Total capital investment	8,263,000	164.8

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-35. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW new oil-fired power unit, 2.5% S in fuel, 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	38.2 M tons	4.00/ton	152,800	5.38
Subtotal raw material			152,800	5.38
Conversion costs				
Operating labor and supervision	17,520 man-hr	8.00/man-hr	140,200	4.93
Utilities				
Fuel oil (No. 6)	900,000 gal	0.23/gal	207,000	7.28
Process water	76,700 M gal	0.08/M gal	6,100	0.21
Electricity	20,160,000 kWh	0.019/kWh	383,000	13.48
Maintenance				
Labor and material, .09 x 5,016,000			451,400	15.89
Analyses			15,600	0.55
Subtotal conversion costs			1,203,300	42.34
Subtotal direct costs			1,356,100	47.72
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,231,200	43.32
Overhead				
Plant, 20% of conversion costs			240,700	8.47
Administrative, 10% of operating labor			14,000	0.49
Subtotal indirect costs			1,485,900	52.28
Total annual operating cost			2,842,000	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.38	2.03	22.07	362.96

[a] Basis:

Remaining life of power plant, 30 yr.
Oil burned, 2,058,200 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $8,263,000; subtotal direct investment, $5,016,000.
Working capital, $225,600.

Table B-36

LIMESTONE SLURRY PROCESS, 200 MW. NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 8263000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	2058200	7800	44900	0.0	3701600	0	3701600	3701600
2	7000	12880000	2058200	7800	44900	0.0	3644300	0	3644300	7345900
3	7000	12880000	2058200	7800	44900	0.0	3587000	0	3587000	10932900
4	7000	12880000	2058200	7800	44900	0.0	3529800	0	3529800	14462700
5	7000	12880000	2058200	7800	44900	0.0	3472500	0	3472500	17935200
6	7000	12880000	2058200	7800	44900	0.0	3415200	0	3415200	21350400
7	7000	12880000	2058200	7800	44900	0.0	3357900	0	3357900	24708300
8	7000	12880000	2058200	7800	44900	0.0	3300600	0	3300600	28008900
9	7000	12880000	2058200	7800	44900	0.0	3243300	0	3243300	31252200
10	7000	12880000	2058200	7800	44900	0.0	3186100	0	3186100	34438300
11	5000	9200000	1470100	5600	32100	0.0	2748300	0	2748300	37186600
12	5000	9200000	1470100	5600	32100	0.0	2691000	0	2691000	39877600
13	5000	9200000	1470100	5600	32100	0.0	2633700	0	2633700	42511300
14	5000	9200000	1470100	5600	32100	0.0	2576400	0	2576400	45087700
15	5000	9200000	1470100	5600	32100	0.0	2519100	0	2519100	47606800
16	3500	6440000	1029100	3900	22500	0.0	2161300	0	2161300	49768100
17	3500	6440000	1029100	3900	22500	0.0	2104000	0	2104000	51872100
18	3500	6440000	1029100	3900	22500	0.0	2046700	0	2046700	53918800
19	3500	6440000	1029100	3900	22500	0.0	1989400	0	1989400	55908200
20	3500	6440000	1029100	3900	22500	0.0	1932100	0	1932100	57840300
21	1500	2760000	441000	1700	9600	0.0	1434400	0	1434400	59274700
22	1500	2760000	441000	1700	9600	0.0	1377200	0	1377200	60651900
23	1500	2760000	441000	1700	9600	0.0	1319900	0	1319900	61971800
24	1500	2760000	441000	1700	9600	0.0	1262600	0	1262600	63234400
25	1500	2760000	441000	1700	9600	0.0	1205300	0	1205300	64439700
26	1500	2760000	441000	1700	9600	0.0	1148000	0	1148000	65587700
27	1500	2760000	441000	1700	9600	0.0	1090700	0	1090700	66678400
28	1500	2760000	441000	1700	9600	0.0	1033500	0	1033500	67711900
29	1500	2760000	441000	1700	9600	0.0	976200	0	976200	68688100
30	1500	2760000	441000	1700	9600	0.0	918900	0	918900	69607000
TOT	127500	234600000	37488000	142500	818000		69607000	0	69607000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.86	0.0	1.86	
MILLS PER KILOWATT-HOUR							2.73	0.0	2.73	
CENTS PER MILLION BTU HEAT INPUT							29.67	0.0	29.67	
DOLLARS PER TON OF SULFUR REMOVED							488.47	0.0	488.47	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							28281000	0	28281000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.75	0.0	1.75	
MILLS PER KILOWATT-HOUR							2.58	0.0	2.58	
CENTS PER MILLION BTU HEAT INPUT							28.01	0.0	28.01	
DOLLARS PER TON OF SULFUR REMOVED							462.11	0.0	462.11	

Table B-37. Limestone Slurry Process Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	154,000	1.9
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	296,000	3.6
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between common feed plenum and inlet of fan)	4,240,000	51.3
Stack gas reheat (4 direct oil-fired reheaters)	252,000	3.1
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	582,000	7.0
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	1,530,000	18.5
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	185,000	2.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	628,000	7.6
Construction facilities	393,000	4.8
Subtotal direct investment	8,260,000	100.0
Engineering design and supervision	743,000	9.0
Construction field expense	909,000	11.0
Contractor fees	413,000	5.0
Contingency	826,000	10.0
Subtotal fixed investment	11,151,000	135.0
Allowance for startup and modifications	892,000	10.8
Interest during construction (8%/annum rate)	892,000	10.8
Total capital investment	12,935,000	156.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-38. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	37.4 M tons	4.00/ton	149,600	3.16
Subtotal raw material			149,600	3.16
Conversion costs				
Operating labor and supervision	17,520 man-hr	8.00/man-hr	140,200	2.96
Utilities				
Fuel oil (No. 6)	2,200,000 gal	0.23/gal	506,000	10.69
Process water	163,300 M gal	0.08/M gal	13,100	0.28
Electricity	47,290,000 kWh	0.018/kWh	851,200	18.00
Maintenance				
Labor and material, .08 x 8,260,000			660,800	13.96
Analyses			30,000	0.63
Subtotal conversion costs			2,201,300	46.52
Subtotal direct costs			2,350,900	49.68
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,927,300	40.72
Overhead				
Plant, 20% of conversion costs			440,300	9.30
Administrative, 10% of operating labor			14,000	0.30
Subtotal indirect costs			2,381,600	50.32
Total annual operating cost			4,732,500	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	0.94	1.35	15.02	618.63

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $12,935,000; subtotal direct investment, $8,260,000.
Working capital, $386,200.

Table B-39

LIMESTONE SLURRY PROCESS, 500 MW. NEW, OIL FIRED POWER UNIT, 1.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 12935000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	7700	43900	0.0	6078200	0	6078200	6078200
2	7000	31500000	5033600	7700	43900	0.0	5988500	0	5988500	12066700
3	7000	31500000	5033600	7700	43900	0.0	5898800	0	5898800	17965500
4	7000	31500000	5033600	7700	43900	0.0	5809100	0	5809100	23774600
5	7000	31500000	5033600	7700	43900	0.0	5719400	0	5719400	29494000
6	7000	31500000	5033600	7700	43900	0.0	5629700	0	5629700	35123700
7	7000	31500000	5033600	7700	43900	0.0	5540000	0	5540000	40663700
8	7000	31500000	5033600	7700	43900	0.0	5450400	0	5450400	46114100
9	7000	31500000	5033600	7700	43900	0.0	5360700	0	5360700	51474800
10	7000	31500000	5033600	7700	43900	0.0	5271000	0	5271000	56745800
11	5000	22500000	3595400	5500	31400	0.0	4485200	0	4485200	61231000
12	5000	22500000	3595400	5500	31400	0.0	4395500	0	4395500	65626500
13	5000	22500000	3595400	5500	31400	0.0	4305800	0	4305800	69932300
14	5000	22500000	3595400	5500	31400	0.0	4216100	0	4216100	74148400
15	5000	22500000	3595400	5500	31400	0.0	4126400	0	4126400	78274800
16	3500	15750000	2516800	3800	22000	0.0	3494500	0	3494500	81769300
17	3500	15750000	2516800	3800	22000	0.0	3404800	0	3404800	85174100
18	3500	15750000	2516800	3800	22000	0.0	3315200	0	3315200	88489300
19	3500	15750000	2516800	3900	22000	0.0	3225500	0	3225500	91714800
20	3500	15750000	2516800	3800	22000	0.0	3135800	0	3135800	94850600
21	1500	6750000	1078600	1600	9400	0.0	2270300	0	2270300	97120900
22	1500	6750000	1078600	1600	9400	0.0	2180600	0	2180600	99301500
23	1500	6750000	1078600	1600	9400	0.0	2090900	0	2090900	101392400
24	1500	6750000	1078600	1600	9400	0.0	2001200	0	2001200	103393600
25	1500	6750000	1078600	1600	9400	0.0	1911500	0	1911500	105305100
26	1500	6750000	1078600	1600	9400	0.0	1821800	0	1821800	107126900
27	1500	6750000	1078600	1600	9400	0.0	1732200	0	1732200	108859100
28	1500	6750000	1078600	1600	9400	0.0	1642500	0	1642500	110501600
29	1500	6750000	1076600	1600	9400	0.0	1552800	0	1552800	112054400
30	1500	6750000	1078600	1600	9400	0.0	1463100	0	1463100	113517500
TOT	127500	573750000	91683000	139500	600000		113517500	0	113517500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.24	0.0	1.24	
MILLS PER KILOWATT-HOUR							1.78	0.0	1.78	
CENTS PER MILLION BTU HEAT INPUT							19.79	0.0	19.79	
DOLLARS PER TON OF SULFUR REMOVED							813.75	0.0	813.75	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							46404800	0	46404800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.18	0.0	1.18	
MILLS PER KILOWATT-HOUR							1.69	0.0	1.69	
CENTS PER MILLION BTU HEAT INPUT							18.80	0.0	18.80	
DOLLARS PER TON OF SULFUR REMOVED							770.84	0.0	770.84	

Table B-40. Limestone Slurry Process Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	279,000	2.8
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	572,000	5.8
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between common feed plenum and inlet of fan)	4,240,000	42.9
Stack gas reheat (4 direct oil-fired reheaters)	252,000	2.5
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	582,000	5.9
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	2,672,000	27.0
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	185,000	1.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	628,000	6.4
Construction facilities	471,000	4.8
Subtotal direct investment	9,881,000	100.0
Engineering design and supervision	889,000	9.0
Construction field expense	1,087,000	11.0
Contractor fees	494,000	5.0
Contingency	988,000	10.0
Subtotal fixed investment	13,339,000	135.0
Allowance for startup and modifications	1,067,000	10.8
Interest during construction (8%/annum rate)	1,067,000	10.8
Total capital investment	15,473,000	156.6

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-41. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	93.4 M tons	4.00/ton	373,600	6.71
Subtotal raw material			373,600	6.71
Conversion				
Operating labor and supervision	19,600 man-hr	8.00/man-hr	156,800	2.82
Utilities				
Fuel oil (No. 6)	2,200,000 gal	0.23/gal	506,000	9.09
Process water	187,500 M gal	0.08/M gal	15,000	0.27
Electricity	49,280,000 kWh	0.018/kWh	887,000	15.94
Maintenance				
Labor and material, .08 x 9,881,000			790,500	14.21
Analyses			36,000	0.65
Subtotal conversion costs			2,391,300	42.98
Subtotal direct costs			2,764,900	49.69
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,305,500	41.43
Overhead				
Plant, 20% of conversion costs			478,300	8.60
Administrative, 10% of operating labor			15,700	0.28
Subtotal indirect costs			2,799,500	50.31
Total annual operating cost			5,564,400	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.11	1.59	17.66	290.87

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $15,473,000; subtotal direct investment, $9,881,000.
Working capital, $460,300.

Table B-42

LIMESTONE SLURRY PROCESS, 500 MW. NEW, OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 15473000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	19100	109900	0.0	7174100	0	7174100	7174100
2	7000	31500000	5033600	19100	109900	0.0	7066800	0	7066800	14240900
3	7000	31500000	5033600	19100	109900	0.0	6959500	0	6959500	21200400
4	7000	31500000	5033600	19100	109900	0.0	6852200	0	6852200	28052600
5	7000	31500000	5033600	19100	109900	0.0	6744900	0	6744900	34797500
6	7000	31500000	5033600	19100	109900	0.0	6637700	0	6637700	41435200
7	7000	31500000	5033600	19100	109900	0.0	6530400	0	6530400	47965600
8	7000	31500000	5033600	19100	109900	0.0	6423100	0	6423100	54388700
9	7000	31500000	5033600	19100	109900	0.0	6315800	0	6315800	60704500
10	7000	31500000	5033600	19100	109900	0.0	6208500	0	6208500	66913000
11	5000	22500000	3595400	13700	78500	0.0	5294400	0	5294400	72207400
12	5000	22500000	3595400	13700	78500	0.0	5187100	0	5187100	77394500
13	5000	22500000	3595400	13700	78500	0.0	5079800	0	5079800	82474300
14	5000	22500000	3595400	13700	78500	0.0	4972600	0	4972600	87446900
15	5000	22500000	3595400	13700	78500	0.0	4865300	0	4865300	92312200
16	3500	15750000	2516800	9600	54900	0.0	4129100	0	4129100	96441300
17	3500	15750000	2516800	9600	54900	0.0	4021800	0	4021800	100463100
18	3500	15750000	2516800	9600	54900	0.0	3914500	0	3914500	104377600
19	3500	15750000	2516800	9600	54900	0.0	3807200	0	3807200	108184800
20	3500	15750000	2516800	9600	54900	0.0	3699900	0	3699900	111884700
21	1500	6750000	1078600	4100	23500	0.0	2691700	0	2691700	114576400
22	1500	6750000	1078600	4100	23500	0.0	2584400	0	2584400	117160800
23	1500	6750000	1078600	4100	23500	0.0	2477100	0	2477100	119637900
24	1500	6750000	1078600	4100	23500	0.0	2369800	0	2369800	122007700
25	1500	6750000	1078600	4100	23500	0.0	2262500	0	2262500	124270200
26	1500	6750000	1078600	4100	23500	0.0	2155200	0	2155200	126425400
27	1500	6750000	1078600	4100	23500	0.0	2047900	0	2047900	128473300
28	1500	6750000	1078600	4100	23500	0.0	1940700	0	1940700	130414000
29	1500	6750000	1078600	4100	23500	0.0	1833400	0	1833400	132247400
30	1500	6750000	1078600	4100	23500	0.0	1726100	0	1726100	133973500
TOT	127500	573750000	91683000	348500	2001000		133973500	0	133973500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.46	0.0	1.46
MILLS PER KILOWATT-HOUR	2.10	0.0	2.10
CENTS PER MILLION BTU HEAT INPUT	23.35	0.0	23.35
DOLLARS PER TON OF SULFUR REMOVED	384.43	0.0	384.43
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	54743900	0	54743900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.39	0.0	1.39
MILLS PER KILOWATT-HOUR	2.00	0.0	2.00
CENTS PER MILLION BTU HEAT INPUT	22.17	0.0	22.17
DOLLARS PER TON OF SULFUR REMOVED	365.45	0.0	365.45

Table B-43. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	379,000	3.4
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	802,000	7.2
Sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between common feed plenum and inlet of fan)	4,240,000	38.0
Stack gas reheat (4 direct oil-fired reheaters)	252,000	2.3
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	582,000	5.2
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	3,562,000	31.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	185,000	1.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	628,000	5.6
Construction facilities	532,000	4.8
Subtotal direct investment	11,162,000	100.0
Engineering design and supervision	1,005,000	9.0
Construction field expense	1,228,000	11.0
Contractor fees	558,000	5.0
Contingency	1,116,000	10.0
Subtotal fixed investment	15,069,000	135.0
Allowance for startup and modifications	1,206,000	10.8
Interest during construction (8%/annum rate)	1,206,000	10.8
Total capital investment	17,481,000	156.6

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-44. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	149.4 M tons	4.00/ton	597,600	9.51
Subtotal raw material			597,600	9.51
Conversion costs				
Operating labor and supervision	21,680 man-hr	8.00/man-hr	173,400	2.76
Utilities				
Fuel oil (No. 6)	2,200,000 gal	0.23/gal	506,000	8.06
Process water	211,700 M gal	0.08/M gal	16,900	0.27
Electricity	51,270,000 kWh	0.018/kWh	922,900	14.69
Maintenance				
Labor and material, .08 x 11,162,000			893,000	14.22
Analyses			39,600	0.63
Subtotal conversion costs			2,551,800	40.63
Subtotal direct costs			3,149,400	50.14
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,604,700	41.45
Overhead				
Plant, 20% of conversion costs			510,400	8.13
Administrative, 10% of operating labor			17,300	0.28
Subtotal indirect costs			3,132,400	49.86
Total annual operating cost			6,281,800	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.25	1.79	19.94	205.15

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $17,481,000; subtotal direct investment, $11,162,000.
Working capital, $529,500.

Table B-45

LIMESTONE SLURRY PROCESS, 500 MW. NEW, OIL FIRED POWER UNIT, 4.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 17481000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	30600	175800	0.0	8100300	0	8100300	8100300
2	7000	31500000	5033600	30600	175800	0.0	7979100	0	7979100	16079400
3	7000	31500000	5033600	30600	175800	0.0	7857900	0	7857900	23937300
4	7000	31500000	5033600	30600	175800	0.0	7736700	0	7736700	31674000
5	7000	31500000	5033600	30600	175800	0.0	7615500	0	7615500	39289500
6	7000	31500000	5033600	30600	175800	0.0	7494300	0	7494300	46783800
7	7000	31500000	5033600	30600	175800	0.0	7373100	0	7373100	54156900
8	7000	31500000	5033600	30600	175800	0.0	7251900	0	7251900	61408800
9	7000	31500000	5033600	30600	175800	0.0	7130700	0	7130700	68539500
10	7000	31500000	5033600	30600	175800	0.0	7009500	0	7009500	75549000
11	5000	22500000	3595400	21900	125600	0.0	5977600	0	5977600	81526600
12	5000	22500000	3595400	21900	125600	0.0	5856400	0	5856400	87383000
13	5000	22500000	3595400	21900	125600	0.0	5735200	0	5735200	93118200
14	5000	22500000	3595400	21900	125600	0.0	5614000	0	5614000	98732200
15	5000	22500000	3595400	21900	125600	0.0	5492800	0	5492800	104225000
16	3500	15750000	2516800	15300	87900	0.0	4661600	0	4661600	108886600
17	3500	15750000	2516800	15300	87900	0.0	4540400	0	4540400	113427000
18	3500	15750000	2516800	15300	87900	0.0	4419200	0	4419200	117846200
19	3500	15750000	2516800	15300	87900	0.0	4298000	0	4298000	122144200
20	3500	15750000	2516800	15300	87900	0.0	4176800	0	4176800	126321000
21	1500	6750000	1078600	6600	37700	0.0	3038800	0	3038800	129359800
22	1500	6750000	1078600	6600	37700	0.0	2917600	0	2917600	132277400
23	1500	6750000	1078600	6600	37700	0.0	2796400	0	2796400	135073800
24	1500	6750000	1078600	6600	37700	0.0	2675200	0	2675200	137749000
25	1500	6750000	1078600	6600	37700	0.0	2554000	0	2554000	140303000
26	1500	6750000	1078600	6600	37700	0.0	2432800	0	2432800	142735800
27	1500	6750000	1078600	6600	37700	0.0	2311600	0	2311600	145047400
28	1500	6750000	1078600	6600	37700	0.0	2190400	0	2190400	147237800
29	1500	6750000	1078600	6600	37700	0.0	2069200	0	2069200	149307000
30	1500	6750000	1078600	6600	37700	0.0	1948000	0	1948000	151255000
TOT	127500	573750000	91683000	558000	3202500		151255000	0	151255000	

	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.65	0.0	1.65
MILLS PER KILOWATT-HOUR	2.37	0.0	2.37
CENTS PER MILLION BTU HEAT INPUT	26.36	0.0	26.36
DOLLARS PER TON OF SULFUR REMOVED	271.07	0.0	271.07
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	61808400	0	61808400
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.57	0.0	1.57
MILLS PER KILOWATT-HOUR	2.25	0.0	2.25
CENTS PER MILLION BTU HEAT INPUT	25.03	0.0	25.03
DOLLARS PER TON OF SULFUR REMOVED	257.64	0.0	257.64

Table B-46. Limestone Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	320,000	2.8
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	636,000	5.6
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between outlet of supplemental fans and stack gas plenum)	4,636,000	40.6
Stack gas reheat (4 direct oil-fired reheaters)	270,000	2.4
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,533,000	13.4
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	2,463,000	21.6
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	311,000	2.7
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	694,000	6.1
Construction facilities	543,000	4.8
Subtotal direct investment	11,406,000	100.0
Engineering design and supervision	1,141,000	10.0
Construction field expense	1,483,000	13.0
Contractor fees	798,000	7.0
Contingency	1,255,000	11.0
Subtotal fixed investment	16,083,000	141.0
Allowance for startup and modifications	1,287,000	11.3
Interest during construction (8%/annum rate)	1,287,000	11.3
Total capital investment	18,657,000	163.6

[a] Basis:

Stack gas reheat to 175 °F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-47. Limestone Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal, on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	95.4 M tons	4.00/ton	381,600	5.79
Subtotal raw material			381,600	5.79
Conversion costs				
Operating labor and supervision	19,600 man-hr	8.00/man-hr	156,800	2.38
Utilities				
Fuel oil (No. 6)	3,040,000 gal	0.23/gal	699,200	10.61
Process water	191,500 M gal	0.08/M gal	15,300	0.23
Electricity	53,320,000 kWh	0.018/kWh	959,800	14.58
Maintenance				
Labor and material, .08 x 11,406,000			912,500	13.85
Analyses			36,000	0.55
Subtotal conversion costs			2,779,600	42.20
Subtotal direct costs			3,161,200	47.99
Indirect Costs				
Average capital charges at 15.3% of total capital investment			2,854,500	43.33
Overhead				
Plant, 20% of conversion costs			555,900	8.44
Administrative, 10% of operating labor			15,700	0.24
Subtotal indirect costs			3,426,100	52.01
Total annual operating cost			6,587,300	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.28	1.88	20.46	336.77

[a] Basis:
Remaining life of power plant, 25 yr.
Oil burned, 5,145,400 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $18,657,000; subtotal direct investment, $11,406,000.
Working capital, $524,500.

Table B-48

LIMESTONE SLURRY PROCESS, 500 MW. EXISTING OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 18657000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5145400	19600	112300	0.0	8527700	0	8527700	8527700
7	7000	32200000	5145400	19600	112300	0.0	8372400	0	8372400	16900100
8	7000	32200000	5145400	19600	112300	0.0	8217200	0	8217200	25117300
9	7000	32200000	5145400	19600	112300	0.0	8062000	0	8062000	33179300
10	7000	32200000	5145400	19600	112300	0.0	7906700	0	7906700	41086000
11	5000	23000000	3675300	14000	80200	0.0	6824200	0	6824200	47910200
12	5000	23000000	3675300	14000	80200	0.0	6669000	0	6669000	54579200
13	5000	23000000	3675300	14000	80200	0.0	6513700	0	6513700	61092900
14	5000	23000000	3675300	14000	80200	0.0	6358500	0	6358500	67451400
15	5000	23000000	3675300	14000	80200	0.0	6203300	0	6203300	73654700
16	3500	16100000	2572700	9800	56100	0.0	5326200	0	5326200	78980900
17	3500	16100000	2572700	9800	56100	0.0	5170900	0	5170900	84151800
18	3500	16100000	2572700	9800	56100	0.0	5015700	0	5015700	89167500
19	3500	16100000	2572700	9800	56100	0.0	4860500	0	4860500	94028000
20	3500	16100000	2572700	9800	56100	0.0	4705200	0	4705200	98733200
21	1500	6900000	1102600	4200	24100	0.0	3516900	0	3516900	102250100
22	1500	6900000	1102600	4200	24100	0.0	3361700	0	3361700	105611800
23	1500	6900000	1102600	4200	24100	0.0	3206400	0	3206400	108818200
24	1500	6900000	1102600	4200	24100	0.0	3051200	0	3051200	111869400
25	1500	6900000	1102600	4200	24100	0.0	2896000	0	2896000	114765400
26	1500	6900000	1102600	4200	24100	0.0	2740700	0	2740700	117506100
27	1500	6900000	1102600	4200	24100	0.0	2585500	0	2585500	120091600
28	1500	6900000	1102600	4200	24100	0.0	2430300	0	2430300	122521900
29	1500	6900000	1102600	4200	24100	0.0	2275100	0	2275100	124797000
30	1500	6900000	1102600	4200	24100	0.0	2119800	0	2119800	126916800
TOT	92500	425500000	67993000	259000	1484000		126916800	0	126916800	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE)
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.87	0.0	1.87
MILLS PER KILOWATT-HOUR	2.74	0.0	2.74
CENTS PER MILLION BTU HEAT INPUT	29.83	0.0	29.83
DOLLARS PER TON OF SULFUR REMOVED	490.03	0.0	490.03
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	58358800	0	58358800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.74	0.0	1.74
MILLS PER KILOWATT-HOUR	2.56	0.0	2.56
CENTS PER MILLION BTU HEAT INPUT	27.81	0.0	27.81
DOLLARS PER TON OF SULFUR REMOVED	457.00	0.0	457.00

Table B-49. Limestone Slurry Process Summary of Estimated Fixed Investment[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Limestone receiving and storage (hoppers, feeders, conveyors, elevators, and bins)	428,000	2.8
Feed preparation (feeders, crushers, elevators, ball mills, tanks, and pumps)	919,000	6.0
Sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum, mist eliminators, effluent hold tanks, agitators, pumps, and all ductwork between common feed plenum and inlet of fan)	6,836,000	44.8
Stack gas reheat (4 direct oil-fired reheaters)	435,000	2.8
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	881,000	5.8
Calcium solids disposal (on-site disposal facilities including feed tank, agitator, slurry disposal pumps, pond, liner, and pond water return pumps)	3,998,000	26.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	246,000	1.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	801,000	5.2
Construction facilities	727,000	4.8
Subtotal direct investment	15,271,000	100.0
Engineering design and supervision	1,222,000	8.0
Construction field expense	1,527,000	10.0
Contractor fees	764,000	5.0
Contingency	1,374,000	9.0
Subtotal fixed investment	20,158,000	132.0
Allowance for startup and modifications	1,613,000	10.6
Interest during construction (8%/annum rate)	1,613,000	10.6
Total capital investment	23,384,000	153.2

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-50. Limestone Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Limestone	180.5 M tons	4.00/ton	722,000	8.03
Subtotal raw material			722,000	8.03
Conversion costs				
Operating labor and supervision	25,840 man-hr	8.00/man-hr	206,700	2.30
Utilities				
Fuel oil (No. 6)	4,250,000 gal	0.23/gal	977,500	10.88
Process water	362,500 M gal	0.08/M gal	29,000	0.32
Electricity	95,300,000 kWh	0.017/kWh	1,620,100	18.03
Maintenance				
Labor and material, .07 x 15,271,000			1,069,000	11.89
Analyses			64,800	0.72
Subtotal conversion costs			3,967,100	44.14
Subtotal direct costs			4,689,100	52.17
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,484,200	38.77
Overhead				
Plant, 20% of conversion costs			793,400	8.83
Administrative, 10% of operating labor			20,700	0.23
Subtotal indirect costs			4,298,300	47.83
Total annual operating cost			8,987,400	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	0.92	1.28	14.76	242.97

[a] Basis:

Remaining life of power plant. 30 yr.
Oil burned. 9.731.500 bbl/yr. 8,700 Btu/kWh
Stack gas reheat to 175° F.
Power unit on-stream time. 7,000 hr/yr.
Midwest plant location. 1975 operating costs.
Total capital investment. $23.384.000; subtotal direct investment. $15.271.000.
Working capital. $782.500.

Table B-51

LIMESTONE SLURRY PROCESS, 1000 MW. NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 23384000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	9731500	37000	212400	0.0	11420200	0	11420200	11420200
2	7000	60900000	9731500	37000	212400	0.0	11258000	0	11258000	22678200
3	7000	60900000	9731500	37000	212400	0.0	11095900	0	11095900	33774100
4	7000	60900000	9731500	37000	212400	0.0	10933800	0	10933800	44707900
5	7000	60900000	9731500	37000	212400	0.0	10771600	0	10771600	55479500
6	7000	60900000	9731500	37000	212400	0.0	10609500	0	10609500	66089000
7	7000	60900000	9731500	37000	212400	0.0	10447400	0	10447400	76536400
8	7000	60900000	9731500	37000	212400	0.0	10285200	0	10285200	86821600
9	7000	60900000	9731500	37000	212400	0.0	10123100	0	10123100	96944700
10	7000	60900000	9731500	37000	212400	0.0	9960900	0	9960900	106905600
11	5000	43500000	6951100	26400	151700	0.0	8393600	0	8393600	115299200
12	5000	43500000	6951100	26400	151700	0.0	8231500	0	8231500	123530700
13	5000	43500000	6951100	26400	151700	0.0	8069300	0	8069300	131600000
14	5000	43500000	6951100	26400	151700	0.0	7907200	0	7907200	139507200
15	5000	43500000	6951100	26400	151700	0.0	7745100	0	7745100	147252300
16	3500	30450000	4865800	18500	106200	0.0	6497300	0	6497300	153749600
17	3500	30450000	4865800	18500	106200	0.0	6335200	0	6335200	160084800
18	3500	30450000	4865800	18500	106200	0.0	6173100	0	6173100	166257900
19	3500	30450000	4865800	18500	106200	0.0	6010900	0	6010900	172268800
20	3500	30450000	4865800	18500	106200	0.0	5848800	0	5848800	178117600
21	1500	13050000	2085300	7900	45500	0.0	4154600	0	4154600	182272200
22	1500	13050000	2085300	7900	45500	0.0	3992400	0	3992400	186264600
23	1500	13050000	2085300	7900	45500	0.0	3830300	0	3830300	190094900
24	1500	13050000	2085300	7900	45500	0.0	3668100	0	3668100	193763000
25	1500	13050000	2085300	7900	45500	0.0	3506000	0	3506000	197269000
26	1500	13050000	2085300	7900	45500	0.0	3343900	0	3343900	200612900
27	1500	13050000	2085300	7900	45500	0.0	3181700	0	3181700	203794600
28	1500	13050000	2085300	7900	45500	0.0	3019600	0	3019600	206814200
29	1500	13050000	2085300	7900	45500	0.0	2857500	0	2857500	209671700
30	1500	13050000	2085300	7900	45500	0.0	2695300	0	2695300	212367000
TOT	127500	1109250000	177252500	673500	3668500		212367000	0	212367000	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.20	0.0	1.20
MILLS PER KILOWATT-HOUR	1.67	0.0	1.67
CENTS PER MILLION BTU HEAT INPUT	19.15	0.0	19.15
DOLLARS PER TON OF SULFUR REMOVED	315.32	0.0	315.32
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	87171700	0	87171700
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.14	0.0	1.14
MILLS PER KILOWATT-HOUR	1.59	0.0	1.59
CENTS PER MILLION BTU HEAT INPUT	18.26	0.0	18.26
DOLLARS PER TON OF SULFUR REMOVED	300.70	0.0	300.70

Table B-52. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(200-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	440,000	6.2
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	220,000	3.1
Particulate - sulfur dioxide scrubbers and inlet ducts (2 scrubbers including common feed plenum and pumps)	1,783,000	25.0
Sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	1,394,000	19.5
Stack gas reheat (2 indirect steam reheaters)	228,000	3.2
Fans (2 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	338,000	4.7
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	1,947,000	27.3
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	47,000	0.7
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	396,000	5.5
Construction facilities	340,000	4.8
Subtotal direct investment	7,133,000	100.0
Engineering design and supervision	785,000	11.0
Construction field expense	927,000	13.0
Contractor fees	499,000	7.0
Contingency	785,000	11.0
Subtotal fixed investment	10,129,000	142.0
Allowance for startup and modifications	810,000	11.4
Interest during construction (8%/annum rate)	810,000	11.4
Total capital investment	11,749,000	164.8

[a] Basis:

Stack gas reheat to 175° F by indirect steam reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-53. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	33.2 M tons	26.00/ton	863,200	20.73
Subtotal raw material			863,200	20.73
Conversion costs				
Operating labor and supervision	14,880 man-hr	8.00/man-hr	119,000	2.86
Utilities				
Steam	200,400 M lb	0.80/M lb	160,300	3.85
Process water	99,000 M gal	0.08/M gal	7,900	0.19
Electricity	30,310,000 kWh	0.011/kWh	333,400	8.01
Maintenance				
Labor and material, .09 x 7,133,000			642,000	15.41
Analyses			19,200	0.46
Subtotal conversion costs			1,281,800	30.78
Subtotal direct costs			2,145,000	51.51
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,750,600	42.04
Overhead				
Plant, 20% of conversion costs			256,400	6.16
Administrative, 10% of operating labor			11,900	0.29
Subtotal indirect costs			2,018,900	48.49
Total annual operating cost			4,163,900	100.0

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	7.76	2.97	32.33	283.84

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $11,749,000; subtotal direct investment, $7,133,000.
Working capital, $374,700.
Investment and operating cost for disposal of fly ash excluded.

Table B-54

```
LIME SLURRY PROCESS, 200 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

                                            FIXED INVESTMENT:  $   11749000
                                                                                      TOTAL
                                        SULFUR        BY-PRODUCT                     OP. COST
                                        REMOVED         RATE,                        INCLUDING               NET ANNUAL     CUMULATIVE
YEARS ANNUAL  POWER UNIT    POWER UNIT     BY         EQUIVALENT     NET REVENUE,   REGULATED     TOTAL      INCREASE     NET INCREASE
AFTER OPERA-    HEAT          FUEL      POLLUTION     TONS/YEAR        $/TON        ROI FOR       NET      (DECREASE)     (DECREASE)
POWER TION,  REQUIREMENT, CONSUMPTION,   CONTROL                                     POWER        SALES     IN COST OF     IN COST OF
UNIT  KW-HR/ MILLION BTU   TONS COAL    PROCESS,       WASTE          WASTE        COMPANY,    REVENUE,     POWER,         POWER,
START   KW      /YEAR        /YEAR     TONS/YEAR       SOLIDS         SOLIDS        $/YEAR      $/YEAR         $              $
------------------------------------------------------------------------------------------------------------------------------------
  1    7000    12880000      536700      14700          71400           0.0        5386200          0      5386200        5386200
  2    7000    12880000      536700      14700          71400           0.0        5304700          0      5304700       10690900
  3    7000    12880000      536700      14700          71400           0.0        5223300          0      5223300       15914200
  4    7000    12880000      536700      14700          71400           0.0        5141800          0      5141800       21056000
--5----7000----12880000------536700------14700----------71400-----------0.0--------5060400----------0------5060400-------26116600
  6    7000    12880000      536700      14700          71400           0.0        4978900          0      4978900       31095300
  7    7000    12880000      536700      14700          71400           0.0        4897500          0      4897500       35992800
  8    7000    12880000      536700      14700          71400           0.0        4816000          0      4816000       40808800
  9    7000    12880000      536700      14700          71400           0.0        4734600          0      4734600       45543400
-10----7000----12880000------536700------14700----------71400-----------0.0--------4653100----------0------4653100-------50196500
 11    5000     9200000      383300      10500          51000           0.0        3981900          0      3981900       54178400
 12    5000     9200000      383300      10500          51000           0.0        3900400          0      3900400       58078800
 13    5000     9200000      383300      10500          51000           0.0        3819000          0      3819000       61897800
 14    5000     9200000      383300      10500          51000           0.0        3737500          0      3737500       65635300
-15----5000-----9200000------383300------10500----------51000-----------0.0--------3656100----------0------3656100-------69291600
 16    3500     6440000      268300       7300          35700           0.0        3112900          0      3112900       72404300
 17    3500     6440000      268300       7300          35700           0.0        3031400          0      3031400       75435700
 18    3500     6440000      268300       7300          35700           0.0        2950000          0      2950000       78385700
 19    3500     6440000      268300       7300          35700           0.0        2868500          0      2868500       81254200
-20----3500-----6440000------268300-------7300----------35700-----------0.0--------2787100----------0------2787100-------84041300
 21    1500     2760000      115000       3100          15300           0.0        2040000          0      2040000       86081300
 22    1500     2760000      115000       3100          15300           0.0        1958600          0      1958600       88039900
 23    1500     2760000      115000       3100          15300           0.0        1877100          0      1877100       89917000
 24    1500     2760000      115000       3100          15300           0.0        1795700          0      1795700       91712700
-25----1500-----2760000------115000-------3100----------15300-----------0.0--------1716200----------0------1716200-------93626900
 26    1500     2760000      115000       3100          15300           0.0        1632800          0      1632800       95059700
 27    1500     2760000      115000       3100          15300           0.0        1551300          0      1551300       96611000
 28    1500     2760000      115000       3100          15300           0.0        1469900          0      1469900       98080900
 29    1500     2760000      115000       3100          15300           0.0        1388400          0      1388400       99469300
-30----1500-----2760000------115000-------3100----------15300-----------0.0--------1307000----------0------1307000------100776300

TOT  127500   234600000     9775000     267000        1300500                    100776300          0    100776300
   LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST
                    DOLLARS PER TON OF COAL BURNED                                   10.31        0.0        10.31
                    MILLS PER KILOWATT-HOUR                                           3.95        0.0         3.95
                    CENTS PER MILLION BTU HEAT INPUT                                 42.96        0.0        42.96
                    DOLLARS PER TON OF SULFUR REMOVED                               377.44        0.0       377.44
PROCESS COST DISCOUNTED AT  10.0% TO INITIAL YEAR, DOLLARS                        41112500          0     41112500
   LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT
                    DOLLARS PER TON OF COAL BURNED                                    9.77        0.0         9.77
                    MILLS PER KILOWATT-HOUR                                           3.75        0.0         3.75
                    CENTS PER MILLION BTU HEAT INPUT                                 40.72        0.0        40.72
                    DOLLARS PER TON OF SULFUR REMOVED                               357.19        0.0       357.19
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Table B-55. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	489,000	6.4
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	250,000	3.3
First stage sulfur dioxide scrubbers and ducts (2 scrubbers including common feed plenum, pumps, and all ductwork between outlet of supplemental fans and the scrubbers)	2,041,000	26.9
Second stage sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and all ductwork between scrubbers and stack gas plenum)	1,691,000	22.3
Stack gas reheat (2 direct oil-fired reheaters)	129,000	1.7
Fans (2 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	506,000	6.6
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	1,425,000	18.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	233,000	3.1
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	468,000	6.1
Construction facilities	362,000	4.8
Subtotal direct investment	7,594,000	100.0
Engineering design and supervision	911,000	12.0
Construction field expense	1,139,000	15.0
Contractor fees	683,000	9.0
Contingency	911,000	12.0
Subtotal fixed investment	11,238,000	148.0
Allowance for startup and modifications	899,000	11.8
Interest during construction (8%/annum rate)	899,000	11.8
Total capital investment	13,036,000	171.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 20 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-56. Lime Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	34.3 M tons	26.00/ton	891,800	18.49
Subtotal raw material			891,800	18.49
Conversion costs				
Operating labor and supervision	14,880 man-hr	8.00/man-hr	119,000	2.47
Utilities				
Fuel oil (No. 6)	1,750,000 gal	0.23/gal	402,500	8.35
Process water	102,200 M gal	0.08/M gal	8,200	0.17
Electricity	27,780,000 kWh	0.011/kWh	305,600	6.34
Maintenance				
Labor and material, .09 x 7,594,000			683,500	14.17
Analyses			19,200	0.40
Subtotal conversion costs			1,538,000	31.90
Subtotal direct costs			2,429,800	50.39
Indirect Costs				
Average capital charges at 15.9% of total capital investment			2,072,700	42.98
Overhead				
Plant, 20% of conversion costs			307,600	6.38
Administrative, 10% of operating labor			11,900	0.25
Subtotal indirect costs			2,392,200	49.61
Total annual operating cost			4,822,000	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	8.70	3.44	36.26	318.28

[a] Basis:
Remaining life of power plant, 20 yr.
Coal burned, 554,200 tons/yr, 9,500 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $13,036,000; subtotal direct investment, $7,594,000.
Working capital, $421,500.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-57

LIME SLURRY PROCESS, 200 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 13036000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	395800	10800	52700	0.0	5496900	0	5496900	5496900
12	5000	9500000	395800	10800	52700	0.0	5361300	0	5361300	10858200
13	5000	9500000	395800	10800	52700	0.0	5225700	0	5225700	16083900
14	5000	9500000	395800	10800	52700	0.0	5090200	0	5090200	21174100
15	5000	9500000	395800	10800	52700	0.0	4954600	0	4954600	26128700
16	3500	6650000	277100	7600	36900	0.0	4288400	0	4288400	30417100
17	3500	6650000	277100	7600	36900	0.0	4152800	0	4152800	34569900
18	3500	6650000	277100	7600	36900	0.0	4017300	0	4017300	38587200
19	3500	6650000	277100	7600	36900	0.0	3881700	0	3881700	42468900
20	3500	6650000	277100	7600	36900	0.0	3746100	0	3746100	46215000
21	1500	2850000	118700	3200	15800	0.0	2850100	0	2850100	49065100
22	1500	2850000	118700	3200	15800	0.0	2714600	0	2714600	51779700
23	1500	2850000	118700	3200	15800	0.0	2579000	0	2579000	54358700
24	1500	2850000	118700	3200	15800	0.0	2443400	0	2443400	56802100
25	1500	2850000	118700	3200	15800	0.0	2307800	0	2307800	59109900
26	1500	2850000	118700	3200	15800	0.0	2172300	0	2172300	61282200
27	1500	2850000	118700	3200	15800	0.0	2036700	0	2036700	63318900
28	1500	2850000	118700	3200	15800	0.0	1901100	0	1901100	65220000
29	1500	2850000	118700	3200	15800	0.0	1765500	0	1765500	66985500
30	1500	2850000	118700	3200	15800	0.0	1630000	0	1630000	68615500
TOT	57500	109250000	4551500	124000	606000		68615500	0	68615500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							15.08	0.0	15.08	
MILLS PER KILOWATT-HOUR							5.97	0.0	5.97	
CENTS PER MILLION BTU HEAT INPUT							62.81	0.0	62.81	
DOLLARS PER TON OF SULFUR REMOVED							553.35	0.0	553.35	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							34979000	0	34979000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							14.37	0.0	14.37	
MILLS PER KILOWATT-HOUR							5.69	0.0	5.69	
CENTS PER MILLION BTU HEAT INPUT							59.88	0.0	59.88	
DOLLARS PER TON OF SULFUR REMOVED							526.79	0.0	526.79	

Table B-58. Lime Slurry Process Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	876,000	5.5
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	436,000	2.7
First stage sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, pumps, and all ductwork between outlet of supplemental fans and the scrubbers)	4,565,000	28.7
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between scrubbers and stack gas plenum)	3,797,000	23.9
Stack gas reheat (4 direct oil-fired reheaters)	305,000	1.9
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,143,000	7.2
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	3,049,000	19.1
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	335,000	2.1
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	649,000	4.1
Construction facilities	758,000	4.8
Subtotal direct investment	15,913,000	100.0
Engineering design and supervision	1,591,000	10.0
Construction field expense	2,069,000	13.0
Contractor fees	1,114,000	7.0
Contingency	1,750,000	11.0
Subtotal fixed investment	22,437,000	141.0
Allowance for startup and modifications	1,795,000	11.3
Interest during construction (8%/annum rate)	1,795,000	11.3
Total capital investment	26,027,000	163.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Remaining life of power unit, 25 yr.

Investment requirements for removal and disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-59. Lime Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	83.0 M tons	22.00/ton	1,826,000	19.00
Subtotal raw material			1,826,000	19.00
Conversion costs				
Operating labor and supervision	22,320 man-hr	8.00/man-hr	178,600	1.86
Utilities				
Fuel oil (No. 6)	4,236,000 gal	0.23/gal	974,300	10.14
Process water	247,300 M gal	0.08/M gal	19,800	0.21
Electricity	67,310,000 kWh	0.010/kWh	673,100	7.00
Maintenance				
Labor and material, .08 x 15,913,000			1,273,000	13.23
Analyses			36,500	0.38
Subtotal conversion costs			3,155,300	32.82
Subtotal direct costs			4,981,300	51.82
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,982,100	41.42
Overhead				
Plant, 20% of conversion costs			631,100	6.57
Administrative, 10% of operating labor			17,900	0.19
Subtotal indirect costs			4,631,100	48.18
Total annual operating cost			9,612,400	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	7.16	2.75	29.85	262.06

[a] Basis:

Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $26,027,000; subtotal direct investment, $15,913,000.
Working capital, $863,300.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-60

LIME SLURRY PROCESS, 500 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 26027000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36700	178600	0.0	12319200	0	12319200	12319200
7	7000	32200000	1341700	36700	178600	0.0	12102700	0	12102700	24421900
8	7000	32200000	1341700	36700	178600	0.0	11886100	0	11886100	36308000
9	7000	32200000	1341700	36700	178600	0.0	11669600	0	11669600	47977600
10	7000	32200000	1341700	36700	178600	0.0	11653000	0	11653000	59630600
11	5000	23000000	958300	26200	127500	0.0	9815300	0	9815300	69445900
12	5000	23000000	958300	26200	127500	0.0	9598700	0	9598700	78844600
13	5000	23000000	958300	26200	127500	0.0	9382200	0	9382200	88226800
14	5000	23000000	958300	26200	127500	0.0	9165600	0	9165600	97392400
15	5000	23000000	958300	26200	127500	0.0	8969100	0	8969100	106361500
16	3500	16100000	670800	18300	89300	0.0	7630600	0	7630600	113972100
17	3500	16100000	670800	18300	89300	0.0	7414100	0	7414100	121386200
18	3500	16100000	670800	18300	89300	0.0	7197500	0	7197500	128563700
19	3500	16100000	670800	18300	89300	0.0	6981000	0	6981000	135564700
20	3500	16100000	670800	18300	89300	0.0	6764400	0	6764400	142329100
21	1500	6900000	287500	7900	38300	0.0	4983800	0	4983800	147312900
22	1500	6900000	287500	7900	38300	0.0	4767200	0	4767200	152080100
23	1500	6900000	287500	7900	38300	0.0	4550700	0	4550700	156630800
24	1500	6900000	287500	7900	38300	0.0	4334100	0	4334100	160964900
25	1500	6900000	287500	7900	38300	0.0	4117600	0	4117600	165082500
26	1500	6900000	287500	7900	38300	0.0	3901000	0	3901000	168983500
27	1500	6900000	287500	7900	38300	0.0	3684500	0	3684500	172668000
28	1500	6900000	287500	7900	38300	0.0	3467900	0	3467900	176135900
29	1500	6900000	287500	7900	38300	0.0	3251400	0	3251400	179387300
30	1500	6900000	287500	7900	38300	0.0	3034800	0	3034800	182422100
TOT	92500	425500000	17729000	485000	2360000		182422100	0	182422100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	10.29	0.0	10.29
MILLS PER KILOWATT-HOUR	3.94	0.0	3.94
CENTS PER MILLION BTU HEAT INPUT	42.87	0.0	42.87
DOLLARS PER TON OF SULFUR REMOVED	376.13	0.0	376.13
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	84117600	0	84117600
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	9.62	0.0	9.62
MILLS PER KILOWATT-HOUR	3.69	0.0	3.69
CENTS PER MILLION BTU HEAT INPUT	40.08	0.0	40.08
DOLLARS PER TON OF SULFUR REMOVED	351.81	0.0	351.81

Table B-61. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	549,000	4.2
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	272,000	2.1
Particulate - sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	4,017,000	31.1
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	3,153,000	24.4
Stack gas reheat (4 indirect steam reheaters)	542,000	4.2
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	767,000	5.9
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	2,386,000	18.5
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	552,000	4.3
Construction facilities	615,000	4.8
Subtotal direct investment	12,920,000	100.0
Engineering design and supervision	1,163,000	9.0
Construction field expense	1,421,000	11.0
Contractor fees	646,000	5.0
Contingency	1,292,000	10.0
Subtotal fixed investment	17,442,000	135.0
Allowance for startup and modifications	1,395,000	10.8
Interest during construction (8%/annum rate)	1,395,000	10.8
Total capital investment	20,232,000	156.6

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-62. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 2.0% S in fuel;
90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	46.4 M tons	24.00/ton	1,113,600	16.10
Subtotal raw material			1,113,600	16.10
Conversion costs				
Operating labor and supervision	18,410 man-hr	8.00/man-hr	147,300	2.13
Utilities				
Steam	490,000 M lb	0.70/M lb	343,000	4.96
Process water	212,400 M gal	0.08/M gal	17,000	0.25
Electricity	73,670,000 kWh	0.010/kWh	736,700	10.65
Maintenance				
Labor and material, .08 x 12,920,000			1,033,600	14.95
Analyses			32,600	0.47
Subtotal conversion costs			2,310,200	33.41
Subtotal direct costs			3,423,800	49.51
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,014,600	43.60
Overhead				
Plant, 20% of conversion costs			462,000	6.68
Administrative, 10% of operating labor			14,700	0.21
Subtotal indirect costs			3,491,300	50.49
Total annual operating cost			6,915,100	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.27	1.98	21.95	337.32

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $20,232,000; subtotal direct investment, $12,920,000.
Working capital, $589,300.
Investment and operating cost for disposal of fly ash excluded.

Table B-63

LIME SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 2.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 20232000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	20500	99800	0.0	9019900	0	9019900	9019900
2	7000	31500000	1312500	20500	99800	0.0	8879600	0	8879600	17899500
3	7000	31500000	1312500	20500	99800	0.0	8739300	0	8739300	26638800
4	7000	31500000	1312500	20500	99800	0.0	8599000	0	8599000	35237800
5	7000	31500000	1312500	20500	99800	0.0	8458800	0	8458800	43696600
6	7000	31500000	1312500	20500	99800	0.0	8318500	0	8318500	52015100
7	7000	31500000	1312500	20500	99800	0.0	8178200	0	8178200	60193300
8	7000	31500000	1312500	20500	99800	0.0	8037900	0	8037900	68231200
9	7000	31500000	1312500	20500	99800	0.0	7897700	0	7897700	76128900
10	7000	31500000	1312500	20500	99800	0.0	7757400	0	7757400	83886300
11	5000	22500000	937500	14600	71300	0.0	6655300	0	6655300	90541600
12	5000	22500000	937500	14600	71300	0.0	6515000	0	6515000	97056600
13	5000	22500000	937500	14600	71300	0.0	6374800	0	6374800	103431400
14	5000	22500000	937500	14600	71300	0.0	6234500	0	6234500	109665900
15	5000	22500000	937500	14600	71300	0.0	6094200	0	6094200	115760100
16	3500	15750000	656200	10300	49900	0.0	5203200	0	5203200	120963300
17	3500	15750000	656200	10300	49900	0.0	5063000	0	5063000	126026300
18	3500	15750000	656200	10300	49900	0.0	4922700	0	4922700	130949000
19	3500	15750000	656200	10300	49900	0.0	4782400	0	4782400	135731400
20	3500	15750000	656200	10300	49900	0.0	4642100	0	4642100	140373500
21	1500	6750000	281200	4400	21400	0.0	3423800	0	3423800	143797300
22	1500	6750000	281200	4400	21400	0.0	3283500	0	3283500	147080800
23	1500	6750000	281200	4400	21400	0.0	3143200	0	3143200	150224000
24	1500	6750000	281200	4400	21400	0.0	3002900	0	3002900	153226900
25	1500	6750000	281200	4400	21400	0.0	2862700	0	2862700	156089600
26	1500	6750000	281200	4400	21400	0.0	2722400	0	2722400	158812000
27	1500	6750000	281200	4400	21400	0.0	2582100	0	2582100	161394100
28	1500	6750000	281200	4400	21400	0.0	2441800	0	2441800	163835900
29	1500	6750000	281200	4400	21400	0.0	2301600	0	2301600	166137500
30	1500	6750000	281200	4400	21400	0.0	2161300	0	2161300	168298800
TOT	127500	573750000	23905500	373500	1818000		168298800	0	168298800	

	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	7.04	0.0	7.04
MILLS PER KILOWATT-HOUR	2.64	0.0	2.64
CENTS PER MILLION BTU HEAT INPUT	29.33	0.0	29.33
DOLLARS PER TON OF SULFUR REMOVED	450.60	0.0	450.60
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	68709000	0	68709000
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	6.68	0.0	6.68
MILLS PER KILOWATT-HOUR	2.50	0.0	2.50
CENTS PER MILLION BTU HEAT INPUT	27.83	0.0	27.83
DOLLARS PER TON OF SULFUR REMOVED	427.56	0.0	427.56

Table B-64. Lime Slurry Process Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	795,000	5.5
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	387,000	2.7
Particulate - sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	4,017,000	28.1
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	3,153,000	22.0
Stack gas reheat (4 indirect steam reheaters)	542,000	3.8
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	767,000	5.4
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	3,356,000	23.4
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	552,000	3.8
Construction facilities	682,000	4.8
Subtotal direct investment	14,318,000	100.0
Engineering design and supervision	1,289,000	9.0
Construction field expense	1,575,000	11.0
Contractor fees	716,000	5.0
Contingency	1,432,000	10.0
Subtotal fixed investment	19,330,000	135.0
Allowance for startup and modifications	1,546,000	10.8
Interest during construction (8%/annum rate)	1,546,000	10.8
Total capital investment	22,422,000	156.6

[a] Basis:
Stack gas reheat to 175°F by indirect steam reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-65. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	81.2 M tons	22.00/ton	1,786,400	22.05
Subtotal raw material			1,786,400	22.05
Conversion costs				
Operating labor and supervision	22,320 man-hr	8.00/man-hr	178,600	2.20
Utilities				
Steam	490,000 M lb	0.70/M lb	343,000	4.23
Process water	241,900 M gal	0.08/M gal	19,400	0.24
Electricity	74,100,000 kWh	0.010/kWh	741,000	9.15
Maintenance				
Labor and material, .08 x 14,318,000			1,145,400	14.14
Analyses			36,500	0.45
Subtotal conversion costs			2,463,900	30.41
Subtotal direct costs			4,250,300	52.46
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,340,900	41.24
Overhead				
Plant, 20% of conversion costs			492,800	6.08
Administrative, 10% of operating labor			17,900	0.22
Subtotal indirect costs			3,851,600	47.54
Total annual operating cost			8,101,900	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	6.17	2.31	25.72	225.81

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $22,422,000; subtotal direct investment, $14,318,000.
Working capital, $744,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-66

LIME SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 22422000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	35900	174700	0.0	10434500	0	10434500	10434500
2	7000	31500000	1312500	35900	174700	0.0	10279000	0	10279000	20713500
3	7000	31500000	1312500	35900	174700	0.0	10123600	0	10123600	30837100
4	7000	31500000	1312500	35900	174700	0.0	9968100	0	9968100	40805200
5	7000	31500000	1312500	35900	174700	0.0	9812600	0	9812600	50617800
6	7000	31500000	1312500	35900	174700	0.0	9657200	0	9657200	60275000
7	7000	31500000	1312500	35900	174700	0.0	9501700	0	9501700	69776700
8	7000	31500000	1312500	35900	174700	0.0	9346300	0	9346300	79123000
9	7000	31500000	1312500	35900	174700	0.0	9190800	0	9190800	88313800
10	7000	31500000	1312500	35900	174700	0.0	9035300	0	9035300	97349100
11	5000	22500000	937500	25600	124800	0.0	7691300	0	7691300	105040400
12	5000	22500000	937500	25600	124800	0.0	7535800	0	7535800	112576200
13	5000	22500000	937500	25600	124800	0.0	7380400	0	7380400	119956600
14	5000	22500000	937500	25600	124800	0.0	7224900	0	7224900	127181500
15	5000	22500000	937500	25600	124800	0.0	7069600	0	7069600	134250900
16	3500	15750000	656200	17900	87300	0.0	5989700	0	5989700	140240600
17	3500	15750000	656200	17900	87300	0.0	5834200	0	5834200	146074800
18	3500	15750000	656200	17900	87300	0.0	5678800	0	5678800	151753600
19	3500	15750000	656200	17900	87300	0.0	5523300	0	5523300	157276900
20	3500	15750000	656200	17900	87300	0.0	5367900	0	5367900	162644800
21	1500	6750000	281200	7700	37400	0.0	3893100	0	3893100	166537900
22	1500	6750000	281200	7700	37400	0.0	3737600	0	3737600	170275500
23	1500	6750000	281200	7700	37400	0.0	3582200	0	3582200	173857700
24	1500	6750000	281200	7700	37400	0.0	3426700	0	3426700	177284400
25	1500	6750000	281200	7700	37400	0.0	3271300	0	3271300	180555700
26	1500	6750000	281200	7700	37400	0.0	3115800	0	3115800	183671500
27	1500	6750000	281200	7700	37400	0.0	2960300	0	2960300	186631800
28	1500	6750000	281200	7700	37400	0.0	2804900	0	2804900	189436700
29	1500	6750000	281200	7700	37400	0.0	2649400	0	2649400	192086100
30	1500	6750000	281200	7700	37400	0.0	2494000	0	2494000	194580100
TOT	127500	573750000	23905500	653500	3181500		194580100	0	194580100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	8.14	0.0	8.14
MILLS PER KILOWATT-HOUR	3.05	0.0	3.05
CENTS PER MILLION BTU HEAT INPUT	33.91	0.0	33.91
DOLLARS PER TON OF SULFUR REMOVED	297.75	0.0	297.75
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	79593300	0	79593300
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	7.74	0.0	7.74
MILLS PER KILOWATT-HOUR	2.90	0.0	2.90
CENTS PER MILLION BTU HEAT INPUT	32.24	0.0	32.24
DOLLARS PER TON OF SULFUR REMOVED	282.95	0.0	282.95

Table B-67. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	1,006,000	6.5
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	485,000	3.1
Particulate - sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	4,017,000	25.9
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	3,153,000	20.3
Stack gas reheat (4 indirect steam reheaters)	542,000	3.5
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	767,000	5.0
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	4,172,000	26.9
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	552,000	3.6
Construction facilities	738,000	4.8
Subtotal direct investment	15,499,000	100.0
Engineering design and supervision	1,395,000	9.0
Construction field expense	1,705,000	11.0
Contractor fees	775,000	5.0
Contingency	1,550,000	10.0
Subtotal fixed investment	20,924,000	135.0
Allowance for startup and modifications	1,674,000	10.8
Interest during construction (8%/annum rate)	1,674,000	10.8
Total capital investment	24,272,000	156.6

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-68. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	116.0 M tons	21.00/ton	2,436,000	26.56
Subtotal raw material			2,436,000	26.56
Conversion costs				
Operating labor and supervision	24,090 man-hr	8.00/man-hr	192,700	2.10
Utilities				
Steam	490,000 M lb	0.70/M lb	343,000	3.74
Process water	271,400 M gal	0.08/M gal	21,700	0.24
Electricity	74,520,000 kWh	0.010/kWh	745,200	8.13
Maintenance				
Labor and material, .08 x 15,499,000			1,239,900	13.52
Analyses			39,400	0.43
Subtotal conversion costs			2,581,900	28.16
Subtotal direct costs			5,017,900	54.72
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,616,500	39.44
Overhead				
Plant, 20% of conversion costs			516,400	5.63
Administrative, 10% of operating labor			19,300	0.21
Subtotal indirect costs			4,152,200	45.28
Total annual operating cost			9,170,100	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	6.99	2.62	29.11	178.89

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $24,272,000; subtotal direct investment, $15,499,000.
Working capital, $888,100.
Investment and operating cost for disposal of fly ash excluded.

Table B-69

LIME SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 5.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 24272000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	51300	249500	0.0	11695300	0	11695300	11695300
2	7000	31500000	1312500	51300	249500	0.0	11527000	0	11527000	23222300
3	7000	31500000	1312500	51300	249500	0.0	11358700	0	11358700	34581000
4	7000	31500000	1312500	51300	249500	0.0	11190400	0	11190400	45771400
5	7000	31500000	1312500	51300	249500	0.0	11022100	0	11022100	56793500
6	7000	31500000	1312500	51300	249500	0.0	10853800	0	10853800	67647300
7	7000	31500000	1312500	51300	249500	0.0	10685500	0	10685500	78332800
8	7000	31500000	1312500	51300	249500	0.0	10517200	0	10517200	88850000
9	7000	31500000	1312500	51300	249500	0.0	10348900	0	10348900	99198900
10	7000	31500000	1312500	51300	249500	0.0	10180600	0	10180600	109379500
11	5000	22500000	937500	36600	178200	0.0	8611400	0	8611400	117990900
12	5000	22500000	937500	36600	178200	0.0	8443200	0	8443200	126434100
13	5000	22500000	937500	36600	178200	0.0	8274900	0	8274900	134709000
14	5000	22500000	937500	36600	178200	0.0	8106600	0	8106600	142815600
15	5000	22500000	937500	36600	178200	0.0	7938300	0	7938300	150753900
16	3500	15750000	656200	25600	124800	0.0	6683700	0	6683700	157437600
17	3500	15750000	656200	25600	124800	0.0	6515400	0	6515400	163953000
18	3500	15750000	656200	25600	124800	0.0	6347100	0	6347100	170300100
19	3500	15750000	656200	25600	124800	0.0	6178800	0	6178800	176478900
20	3500	15750000	656200	25600	124800	0.0	6010500	0	6010500	182489600
21	1500	6750000	281200	11000	53500	0.0	4299700	0	4299700	186789100
22	1500	6750000	281200	11000	53500	0.0	4131400	0	4131400	190920500
23	1500	6750000	281200	11000	53500	0.0	3963100	0	3963100	194883600
24	1500	6750000	281200	11000	53500	0.0	3794800	0	3794800	198678400
25	1500	6750000	281200	11000	53500	0.0	3626500	0	3626500	202304900
26	1500	6750000	281200	11000	53500	0.0	3458300	0	3458300	205763200
27	1500	6750000	281200	11000	53500	0.0	3290000	0	3290000	209053200
28	1500	6750000	281200	11000	53500	0.0	3121700	0	3121700	212174900
29	1500	6750000	281200	11000	53500	0.0	2953400	0	2953400	215128300
30	1500	6750000	281200	11000	53500	0.0	2785100	0	2785100	217913400
TOT	127500	573750000	23905500	934000	4545000		217913400	0	217913400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	9.12	0.0	9.12
MILLS PER KILOWATT-HOUR	3.42	0.0	3.42
CENTS PER MILLION BTU HEAT INPUT	37.98	0.0	37.98
DOLLARS PER TON OF SULFUR REMOVED	233.31	0.0	233.31
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	89293900	0	89293900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	8.68	0.0	8.68
MILLS PER KILOWATT-HOUR	3.25	0.0	3.25
CENTS PER MILLION BTU HEAT INPUT	36.17	0.0	36.17
DOLLARS PER TON OF SULFUR REMOVED	222.12	0.0	222.12

Table B-70. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	1,364,000	5.7
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	666,000	2.8
First stage sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, pumps, and all ductwork between outlet of supplemental fans and the scrubbers)	6,782,000	28.5
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between scrubbers and stack gas plenum)	5,720,000	24.0
Stack gas reheat (4 direct oil-fired reheaters)	543,000	2.3
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,746,000	7.3
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	4,593,000	19.3
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	442,000	1.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	831,000	3.5
Construction facilities	1,134,000	4.8
Subtotal direct investment	23,821,000	100.0
Engineering design and supervision	2,144,000	9.0
Construction field expense	2,859,000	12.0
Contractor fees	1,667,000	7.0
Contingency	2,382,000	10.0
Subtotal fixed investment	32,873,000	138.0
Allowance for startup and modifications	2,630,000	11.0
Interest during construction (8%/annum rate)	2,630,000	11.0
Total capital investment	38,133,000	160.0

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-71. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	162.4 M tons	20.50/ton	3,329,200	21.76
Subtotal raw material			3,329,200	21.76
Conversion costs				
Operating labor and supervision	29,760 man-hr	8.00/man-hr	238,100	1.56
Utilities				
Fuel oil (No. 6)	8,288,000 gal	0.23/gal	1,906,200	12.45
Process water	483,900 M gal	0.08/M gal	38,700	0.25
Electricity	131,680,000 kWh	0.009/kWh	1,185,100	7.75
Maintenance				
Labor and material, .07 x 23,821,000			1,667,500	10.90
Analyses			59,500	0.39
Subtotal conversion costs			5,095,100	33.30
Subtotal direct costs			8,424,300	55.06
Indirect Costs				
Average capital charges at 15.3% of total capital investment			5,834,300	38.12
Overhead				
Plant, 20% of conversion costs			1,019,000	6.66
Administrative, 10% of operating labor			23,800	0.16
Subtotal indirect costs			6,877,100	44.94
Total annual operating cost			15,301,400	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.83	2.19	24.29	213.23

[a] Basis:

Remaining life of power plant, 25 yr.
Coal burned, 2,625,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $38,133,000; subtotal direct investment, $23,821,000.
Working capital, $1,466,500.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-72

LIME SLURRY PROCESS, 1000 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 38133000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	2625000	71800	349400	0.0	19267300	0	19267300	19267300
7	7000	63000000	2625000	71800	349400	0.0	18950000	0	18950000	38217300
8	7000	63000000	2625000	71800	349400	0.0	18632700	0	18632700	56850000
9	7000	63000000	2625000	71800	349400	0.0	18315500	0	18315500	75165500
10	7000	63000000	2625000	71800	349400	0.0	17998200	0	17998200	93163700
11	5000	45000000	1875000	51300	249500	0.0	15222500	0	15222500	108386200
12	5000	45000000	1875000	51300	249500	0.0	14905200	0	14905200	123291400
13	5000	45000000	1875000	51300	249500	0.0	14587900	0	14587900	137879300
14	5000	45000000	1875000	51300	249500	0.0	14270700	0	14270700	152150000
15	5000	45000000	1875000	51300	249500	0.0	13953400	0	13953400	166103400
16	3500	31500000	1312500	35900	174700	0.0	11744900	0	11744900	177848300
17	3500	31500000	1312500	35900	174700	0.0	11427700	0	11427700	189276000
18	3500	31500000	1312500	35900	174700	0.0	11110400	0	11110400	200386400
19	3500	31500000	1312500	35900	174700	0.0	10793200	0	10793200	211179600
20	3500	31500000	1312500	35900	174700	0.0	10475900	0	10475900	221655500
21	1500	13500000	562500	15400	74900	0.0	7512200	0	7512200	229167700
22	1500	13500000	562500	15400	74900	0.0	7195000	0	7195000	236362700
23	1500	13500000	562500	15400	74900	0.0	6877700	0	6877700	243240400
24	1500	13500000	562500	15400	74900	0.0	6560400	0	6560400	249800800
25	1500	13500000	562500	15400	74900	0.0	6243200	0	6243200	256044000
26	1500	13500000	562500	15400	74900	0.0	5925900	0	5925900	261969900
27	1500	13500000	562500	15400	74900	0.0	5608700	0	5608700	267578600
28	1500	13500000	562500	15400	74900	0.0	5291400	0	5291400	272870000
29	1500	13500000	562500	15400	74900	0.0	4974100	0	4974100	277844100
30	1500	13500000	562500	15400	74900	0.0	4656900	0	4656900	282501000
TOT	92500	832500000	34687500	949000	4617000		282501000	0	282501000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							8.14	0.0	8.14	
MILLS PER KILOWATT-HOUR							3.05	0.0	3.05	
CENTS PER MILLION BTU HEAT INPUT							33.93	0.0	33.93	
DOLLARS PER TON OF SULFUR REMOVED							297.68	0.0	297.68	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							130977300	0	130977300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							7.66	0.0	7.66	
MILLS PER KILOWATT-HOUR							2.87	0.0	2.87	
CENTS PER MILLION BTU HEAT INPUT							31.90	0.0	31.90	
DOLLARS PER TON OF SULFUR REMOVED							279.87	0.0	279.87	

Table B-73. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	1,228,000	5.7
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	586,000	2.7
Particulate - sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	5,925,000	27.7
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	4,713,000	22.0
Stack gas reheat (4 indirect steam reheaters)	955,000	4.5
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	1,161,000	5.4
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	5,018,000	23.5
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	88,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	704,000	3.3
Construction facilities	1,019,000	4.8
Subtotal direct investment	21,397,000	100.0
Engineering design and supervision	1,712,000	8.0
Construction field expense	2,140,000	10.0
Contractor fees	1,070,000	5.0
Contingency	1,926,000	9.0
Subtotal fixed investment	28,245,000	132.0
Allowance for startup and modifications	2,260,000	10.6
Interest during construction (8%/annum rate)	2,260,000	10.6
Total capital investment	32,765,000	153.2

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Disposal pond located 1 mile from power plant.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-74. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	157.0 M tons	20.50/ton	3,218,500	25.64
Subtotal raw material			3,218,500	25.64
Conversion costs				
Operating labor and supervision	29,760 man-hr	8.00/man-hr	238,100	1.90
Utilities				
Steam	947,300 M lb	0.60/M lb	568,400	4.53
Process water	467,700 M gal	0.08/M gal	37,400	0.30
Electricity	143,280,000 kWh	0.009/kWh	1,289,500	10.27
Maintenance				
Labor and material, .07 x 21,397,000			1,497,800	11.93
Analyses			59,500	0.47
Subtotal conversion costs			3,690,700	29.40
Subtotal direct costs			6,909,200	55.04
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,882,000	38.89
Overhead				
Plant, 20% of conversion costs			738,100	5.88
Administrative, 10% of operating labor			23,800	0.19
Subtotal indirect costs			5,643,900	44.96
Total annual operating cost			12,553,100	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	4.95	1.79	20.61	180.96

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $32,765,000; subtotal direct investment, $21,397,000.
Working capital, $1,218,300.
Investment and operating cost for disposal of fly ash excluded.

Table B-75

LIME SLURRY PROCESS, 1000 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 32765000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2537500	69400	337700	0.0	15961800	0	15961800	15961800
2	7000	60900000	2537500	69400	337700	0.0	15734600	0	15734600	31696400
3	7000	60900000	2537500	69400	337700	0.0	15507500	0	15507500	47203900
4	7000	60900000	2537500	69400	337700	0.0	15280300	0	15280300	62484200
5	7000	60900000	2537500	69400	337700	0.0	15053100	0	15053100	77537300
6	7000	60900000	2537500	69400	337700	0.0	14825900	0	14825900	92363200
7	7000	60900000	2537500	69400	337700	0.0	14598800	0	14598800	106962000
8	7000	60900000	2537500	69400	337700	0.0	14371600	0	14371600	121333600
9	7000	60900000	2537500	69400	337700	0.0	14144400	0	14144400	135478000
10	7000	60900000	2537500	69400	337700	0.0	13917200	0	13917200	149395200
11	5000	43500000	1812500	49600	241200	0.0	11723700	0	11723700	161118900
12	5000	43500000	1812500	49600	241200	0.0	11496600	0	11496600	172615500
13	5000	43500000	1812500	49600	241200	0.0	11269400	0	11269400	183884900
14	5000	43500000	1812500	49600	241200	0.0	11042200	0	11042200	194927100
15	5000	43500000	1812500	49600	241200	0.0	10815000	0	10815000	205742100
16	3500	30450000	1268700	34700	168900	0.0	9070000	0	9070000	214812100
17	3500	30450000	1268700	34700	168900	0.0	8842800	0	8842800	223654900
18	3500	30450000	1268700	34700	168900	0.0	8615600	0	8615600	232270500
19	3500	30450000	1268700	34700	168900	0.0	8388400	0	8388400	240658900
20	3500	30450000	1268700	34700	168900	0.0	8161200	0	8161200	248820100
21	1500	13050000	543700	14900	72400	0.0	5796100	0	5796100	254616200
22	1500	13050000	543700	14900	72400	0.0	5568900	0	5568900	260185100
23	1500	13050000	543700	14900	72400	0.0	5341700	0	5341700	265526800
24	1500	13050000	543700	14900	72400	0.0	5114500	0	5114500	270641300
25	1500	13050000	543700	14900	72400	0.0	4887400	0	4887400	275528700
26	1500	13050000	543700	14900	72400	0.0	4660200	0	4660200	280188900
27	1500	13050000	543700	14900	72400	0.0	4433000	0	4433000	284621900
28	1500	13050000	543700	14900	72400	0.0	4205800	0	4205800	288827700
29	1500	13050000	543700	14900	72400	0.0	3978600	0	3978600	292806300
30	1500	13050000	543700	14900	72400	0.0	3751500	0	3751500	296557800
TOT	127500	1109250000	46218000	1264500	6151500		296557800	0	296557800	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE)
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	6.42	0.0	6.42
MILLS PER KILOWATT-HOUR	2.33	0.0	2.33
CENTS PER MILLION BTU HEAT INPUT	26.73	0.0	26.73
DOLLARS PER TON OF SULFUR REMOVED	234.53	0.0	234.53
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	121789900	0	121789900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	6.12	0.0	6.12
MILLS PER KILOWATT-HOUR	2.22	0.0	2.22
CENTS PER MILLION BTU HEAT INPUT	25.51	0.0	25.51
DOLLARS PER TON OF SULFUR REMOVED	223.88	0.0	223.88

Table B-76. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	795,000	5.8
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	387,000	2.8
Particulate - sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	4,017,000	29.1
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	2,812,00	20.4
Stack gas reheat (4 indirect steam reheaters)	542,000	3.9
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	718,000	5.2
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	3,238,000	23.5
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	552,000	4.0
Construction facilities	656,000	4.8
Subtotal direct investment	13,784,000	100.0
Engineering design and supervision	1,241,000	9.0
Construction field expense	1,516,000	11.0
Contractor fees	689,000	5.0
Contingency	1,378,000	10.0
Subtotal fixed investment	18,608,000	135.0
Allowance for startup and modifications	1,489,000	10.8
Interest during construction (8%/annum rate)	1,489,000	10.8
Total capital investment	21,586,000	156.6

[a] Basis:
Stack gas reheat to 175°F by indirect steam reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-77. Lime Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	81.2 M tons	22.00/ton	1,786,400	22.88
Subtotal raw material			1,786,400	22.88
Conversion costs				
Operating labor and supervision	22,320 man-hr	8.00/man-hr	178,600	2.29
Utilities				
Steam	490,000 M lb	0.70/M lb	343,000	4.39
Process water	239,400 M gal	0.08/M gal	19,200	0.25
Electricity	64,190,000 kWh	0.010/kWh	641,900	8.22
Maintenance				
Labor and material, .08 x 13,784,000			1,102,700	14.12
Analyses			36,500	0.47
Subtotal conversion costs			2,321,900	29.74
Subtotal direct costs			4,108,300	52.62
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,216,300	41.20
Overhead				
Plant, 20% of conversion costs			464,400	5.95
Administrative, 10% of operating labor			17,900	0.23
Subtotal indirect costs			3,698,600	47.38
Total annual operating cost			7,806,900	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	5.95	2.23	24.78	244.81

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $21,586,000; subtotal direct investment, $13,784,000.
Working capital, $721,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-78

LIME SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 80% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 21516000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	31900	155300	0.0	10052600	0	10052600	10052600
2	7000	31500000	1312500	31900	155300	0.0	9902900	0	9902900	19955500
3	7000	31500000	1312500	31900	155300	0.0	9753300	0	9753300	29708800
4	7000	31500000	1312500	31900	155300	0.0	9603600	0	9603600	39312400
5	7000	31500000	1312500	31900	155300	0.0	9454000	0	9454000	48766400
6	7000	31500000	1312500	31900	155300	0.0	9304300	0	9304300	58070700
7	7000	31500000	1312500	31900	155300	0.0	9154700	0	9154700	67225400
8	7000	31500000	1312500	31900	155300	0.0	9005000	0	9005000	76230400
9	7000	31500000	1312500	31900	155300	0.0	8855300	0	8855300	85085700
10	7000	31500000	1312500	31900	155300	0.0	8705700	0	8705700	93791400
11	5000	22500000	937500	22800	110900	0.0	7410900	0	7410900	101202300
12	5000	22500000	937500	22800	110900	0.0	7261300	0	7261300	108463600
13	5000	22500000	937500	22800	110900	0.0	7111600	0	7111600	115575200
14	5000	22500000	937500	22800	110900	0.0	6962000	0	6962000	122537200
15	5000	22500000	937500	22800	110900	0.0	6812300	0	6812300	129349500
16	3500	15750000	656200	15900	77600	0.0	5771800	0	5771800	135121300
17	3500	15750000	656200	15900	77600	0.0	5622200	0	5622200	140743500
18	3500	15750000	656200	15900	77600	0.0	5472500	0	5472500	146216000
19	3500	15750000	656200	15900	77600	0.0	5322900	0	5322900	151538900
20	3500	15750000	656200	15900	77600	0.0	5173200	0	5173200	156712100
21	1500	6750000	281200	6800	33300	0.0	3752000	0	3752000	160464100
22	1500	6750000	281200	6800	33300	0.0	3602300	0	3602300	164066400
23	1500	6750000	281200	6800	33300	0.0	3452700	0	3452700	167519100
24	1500	6750000	281200	6800	33300	0.0	3303000	0	3303000	170822100
25	1500	6750000	281200	6800	33300	0.0	3153300	0	3153300	173975400
26	1500	6750000	281200	6800	33300	0.0	3003700	0	3003700	176979100
27	1500	6750000	281200	6800	33300	0.0	2854000	0	2854000	179833100
28	1500	6750000	281200	6800	33300	0.0	2704400	0	2704400	182537500
29	1500	6750000	281200	6800	33300	0.0	2554700	0	2554700	185092200
30	1500	6750000	281200	6800	33300	0.0	2405100	0	2405100	187497300
TOT	127500	573750000	23905500	580500	2828500		187497300	0	187497300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	7.84	0.0	7.84
MILLS PER KILOWATT-HOUR	2.94	0.0	2.94
CENTS PER MILLION BTU HEAT INPUT	32.68	0.0	32.68
DOLLARS PER TON OF SULFUR REMOVED	322.99	0.0	322.99
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	76687900	0	76687900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	7.45	0.0	7.45
MILLS PER KILOWATT-HOUR	2.80	0.0	2.80
CENTS PER MILLION BTU HEAT INPUT	31.06	0.0	31.06
DOLLARS PER TON OF SULFUR REMOVED	306.75	0.0	306.75

Table B-79. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; off-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	795,000	6.8
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	387,000	3.3
Particulate - sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	4,017,000	34.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	3,153,000	26.9
Stack gas reheat (4 indirect steam reheaters)	542,000	4.6
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	767,000	6.6
Calcium solids disposal (off-site disposal facilities including feed tank, agitator, pumps, thickener, drum filters, and cake loading silo)	863,000	7.4
Utilities (instrument air generation and supply system, plus distribution systems for obtaining process steam, water, and electricity from the power plant)	67,000	0.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	552,000	4.7
Construction facilities	557,000	4.8
Subtotal direct investment	11,700,000	100.0
Engineering design and supervision	1,053,000	9.0
Construction field expense	1,287,000	11.0
Contractor fees	585,000	5.0
Contingency	1,170,000	10.0
Subtotal fixed investment	15,795,000	135.0
Allowance for startup and modifications	1,264,000	10.8
Interest during construction (8%/annum rate)	1,264,000	10.8
Total capital investment	18,323,000	156.6

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-80. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; off-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	81.2 M tons	22.00/ton	1,786,400	20.67
Subtotal raw material			1,786,400	20.67
Conversion costs				
Operating labor and supervision	22,320 man-hr	8.00/man-hr	178,600	2.07
Utilities				
Steam	490,000 M lb	0.70/M lb	343,000	3.97
Process water	220,900 M gal	0.08/M gal	17,700	0.20
Electricity	74,570,000 kWh	0.010/kWh	745,700	8.63
Maintenance				
Labor and material, .08 x 11,700,000			936,000	10.84
Analyses			36,500	0.42
Subtotal conversion costs			2,257,500	26.13
Subtotal direct costs			4,043,900	46.80
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,730,100	31.59
Overhead				
Plant, 20% of conversion costs			451,500	5.23
Administrative, 10% of operating labor			17,900	0.21
Subtotal indirect costs			3,199,500	37.03
Total annual operating cost excluding trucking and off-site disposal of calcium solids			7,243,400	83.83
Annual cost for trucking and off-site disposal of calcium solids at $4/ton			1,397,600	16.17
Total annual operating cost			8,641,000	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	6.58	2.47	27.43	240.83

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $18,323,000; subtotal direct investment, $11,700,000.
Working capital, $710,600.
Solids disposed, 174,700 tons/yr calcium solids including hydrate water.
174,700 tons/yr associated water.
349,400 tons/yr
Investment and operating cost for disposal of fly ash excluded.

Table B-81

LIME SLURRY PROCESS, 500 MW. NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL.

FIXED INVESTMENT: $ 18323000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	35900	349400	0.0	10547300	0	10547300	10547300
2	7000	31500000	1312500	35900	349400	0.0	10420200	0	10420200	20967500
3	7000	31500000	1312500	35900	349400	0.0	10293200	0	10293200	31260700
4	7000	31500000	1312500	35900	349400	0.0	10166100	0	10166100	41426800
5	7000	31500000	1312500	35900	349400	0.0	10039100	0	10039100	51465900
6	7000	31500000	1312500	35900	349400	0.0	9912100	0	9912100	61378000
7	7000	31500000	1312500	35900	349400	0.0	9785000	0	9785000	71163000
8	7000	31500000	1312500	35900	349400	0.0	9658000	0	9658000	80821000
9	7000	31500000	1312500	35900	349400	0.0	9530900	0	9530900	90351900
10	7000	31500000	1312500	35900	349400	0.0	9403900	0	9403900	99755800
11	5000	22500000	937500	25600	249600	0.0	7733800	0	7733800	107489600
12	5000	22500000	937500	25600	249600	0.0	7606800	0	7606800	115096400
13	5000	22500000	937500	25600	249600	0.0	7479700	0	7479700	122576100
14	5000	22500000	937500	25600	249600	0.0	7352700	0	7352700	129928800
15	5000	22500000	937500	25600	249600	0.0	7225600	0	7225600	137154400
16	3500	15750000	656200	17900	174700	0.0	5913500	0	5913500	143067900
17	3500	15750000	656200	17900	174700	0.0	5786400	0	5786400	148854300
18	3500	15750000	656200	17900	174700	0.0	5659400	0	5659400	154513700
19	3500	15750000	656200	17900	174700	0.0	5532300	0	5532300	160046000
20	3500	15750000	656200	17900	174700	0.0	5405300	0	5405300	165451300
21	1500	6750000	281200	7700	74900	0.0	3624900	0	3624900	169076200
22	1500	6750000	281200	7700	74900	0.0	3497800	0	3497800	172574000
23	1500	6750000	281200	7700	74900	0.0	3370800	0	3370800	175944800
24	1500	6750000	281200	7700	74900	0.0	3243700	0	3243700	179188500
25	1500	6750000	281200	7700	74900	0.0	3116700	0	3116700	182305200
26	1500	6750000	281200	7700	74900	0.0	2989600	0	2989600	185294800
27	1500	6750000	281200	7700	74900	0.0	2862600	0	2862600	188157400
28	1500	6750000	281200	7700	74900	0.0	2735500	0	2735500	190892900
29	1500	6750000	281200	7700	74900	0.0	2608500	0	2608500	193501400
30	1500	6750000	281200	7700	74900	0.0	2481600	0	2481600	195982800
TOT	127500	573750000	23905500	653500	6364500		195982800	0	195982800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	8.20	0.0	8.20
MILLS PER KILOWATT-HOUR	3.07	0.0	3.07
CENTS PER MILLION BTU HEAT INPUT	34.16	0.0	34.16
DOLLARS PER TON OF SULFUR REMOVED	299.90	0.0	299.90
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	80903300	0	80903300
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	7.86	0.0	7.86
MILLS PER KILOWATT-HOUR	2.95	0.0	2.95
CENTS PER MILLION BTU HEAT INPUT	32.77	0.0	32.77
DOLLARS PER TON OF SULFUR REMOVED	287.61	0.0	287.61

Table B-82. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal; particulate scrubber required for fly ash removal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	876,000	5.5
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	436,000	2.7
Particulate - sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, pumps, and all ductwork between outlet of supplemental fans and the scrubbers)	4,565,000	28.6
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between scrubbers and stack gas plenum)	3,797,000	23.8
Stack gas reheat (4 direct oil-fired reheaters)	305,000	1.9
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,179,000	7.4
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	3,049,000	19.1
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	335,000	2.1
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	649,000	4.1
Construction facilities	760,000	4.8
Subtotal direct investment	15,951,000	100.0
Engineering design and supervision	1,595,000	10.0
Construction field expense	2,074,000	13.0
Contractor fees	1,117,000	7.0
Contingency	1,755,000	11.0
Subtotal fixed investment	22,492,000	141.0
Allowance for startup and modifications	1,799,000	11.3
Interest during construction (8%/annum rate)	1,799,000	11.3
Total capital investment	26,090,000	163.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-83. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; on-site solids disposal; particulate scrubber required for fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	83.0 M tons	22.00/ton	1,826,000	18.77
Subtotal raw material			1,826,000	18.77
Conversion costs				
Operating labor and supervision	22,320 man-hr	8.00/man-hr	178,600	1.84
Utilities				
Fuel oil (No. 6)	4,236,000 gal	0.23/gal	974,300	10.02
Process water	247,300 M gal	0.08/M gal	19,800	0.20
Electricity	75,850,000 kWh	0.010/kWh	758,500	7.80
Maintenance				
Labor and material, .08 x 15,951,000			1,276,100	13.10
Analyses			36,500	0.38
Subtotal conversion costs			3,243,800	33.34
Subtotal direct costs			5,069,800	52.11
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,991,800	41.04
Overhead				
Plant, 20% of conversion costs			648,800	6.67
Administrative, 10% of operating labor			17,900	0.18
Subtotal indirect costs			4,658,500	47.89
Total annual operating cost			9,728,300	100.00

	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	7.25	2.78	30.21	265.22

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $26,090,000; subtotal direct investment, $15,951,000.
Working capital, $877,600.
Investment and operating cost for disposal of fly ash excluded.

Table B-84

LIME SLURRY PROCESS, 500 MW. EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, FLYASH REMOVED BY PART. SCRUB.

FIXED INVESTMENT: $ 26090000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36700	178600	0.0	12441600	0	12441600	12441600
7	7000	32200000	1341700	36700	178600	0.0	12224600	0	12224600	24666200
8	7000	32200000	1341700	36700	178600	0.0	12007500	0	12007500	36673700
9	7000	32200000	1341700	36700	178600	0.0	11790400	0	11790400	48464100
10	7000	32200000	1341700	36700	178600	0.0	11573300	0	11573300	60037400
11	5000	23000000	958300	26200	127500	0.0	9905100	0	9905100	69942500
12	5000	23000000	958300	26200	127500	0.0	9688000	0	9688000	79630500
13	5000	23000000	958300	26200	127500	0.0	9470900	0	9470900	89101400
14	5000	23000000	958300	26200	127500	0.0	9253900	0	9253900	98355300
15	5000	23000000	958300	26200	127500	0.0	9036800	0	9036800	107392100
16	3500	16100000	670800	18300	89300	0.0	7695200	0	7695200	115087300
17	3500	16100000	670800	18300	89300	0.0	7478200	0	7478200	122565500
18	3500	16100000	670800	18300	89300	0.0	7261100	0	7261100	129826600
19	3500	16100000	670800	18300	89300	0.0	7044000	0	7044000	136870600
20	3500	16100000	670800	18300	89300	0.0	6827000	0	6827000	143697600
21	1500	6900000	287500	7900	38300	0.0	5015600	0	5015600	148713200
22	1500	6900000	287500	7900	38300	0.0	4798500	0	4798500	153511700
23	1500	6900000	287500	7900	38300	0.0	4581500	0	4581500	158093200
24	1500	6900000	287500	7900	38300	0.0	4364400	0	4364400	162457600
25	1500	6900000	287500	7900	38300	0.0	4147300	0	4147300	166604900
26	1500	6900000	287500	7900	38300	0.0	3930200	0	3930200	170535100
27	1500	6900000	287500	7900	38300	0.0	3713200	0	3713200	174248300
28	1500	6900000	287500	7900	38300	0.0	3496100	0	3496100	177744400
29	1500	6900000	287500	7900	38300	0.0	3279000	0	3279000	181023400
30	1500	6900000	287500	7900	38300	0.0	3062000	0	3062000	184085400
TOT	92500	425500000	.7729000	485000	2360000		184085400	0	184085400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.38	0.0	10.38	
MILLS PER KILOWATT-HOUR							3.98	0.0	3.98	
CENTS PER MILLION BTU HEAT INPUT							43.26	0.0	43.26	
DOLLARS PER TON OF SULFUR REMOVED							379.56	0.0	379.56	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							84924200	0	84924200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.71	0.0	9.71	
MILLS PER KILOWATT-HOUR							3.72	0.0	3.72	
CENTS PER MILLION BTU HEAT INPUT							40.46	0.0	40.46	
DOLLARS PER TON OF SULFUR REMOVED							355.18	0.0	355.18	

Table B-85. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(200-MW new oil-fired power unit, 2.5% S in fuel;
90% SO_2 removal, on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	291,000	5.1
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	148,000	2.6
First stage sulfur dioxide scrubbers and inlet ducts (2 scrubbers including common feed plenum and pumps)	1,611,000	28.0
Second stage sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	1,255,000	21.8
Stack gas reheat (2 direct oil-fired reheaters)	103,000	1.8
Fans (2 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	227,000	3.9
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	1,326,000	23.0
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	129,000	2.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	393,000	6.8
Construction facilities	274,000	4.8
Subtotal direct investment	5,757,000	100.0
Engineering design and supervision	633,000	11.0
Construction field expense	748,000	13.0
Contractor fees	403,000	7.0
Contingency	633,000	11.0
Subtotal fixed investment	8,174,000	142.0
Allowance for startup and modifications	654,000	11.4
Interest during construction (8%/annum rate)	654,000	11.4
Total capital investment	9,482,000	164.8

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-86. Lime Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	17.7 M tons	26.00/ton	460,200	13.48
Subtotal raw material			460,200	13.48
Conversion costs				
Operating labor and supervision	14,880 man-hr	8.00/man-hr	119,000	3.49
Utilities				
Fuel oil (No. 6)	873,000 gal	0.23/gal	200,800	5.88
Process water	74,600 M gal	0.08/M gal	6,000	0.18
Electricity	21,970,000 kWh	0.019/kWh	417,400	12.23
Maintenance				
Labor and material, .09 x 5,757,000			518,100	15.17
Analyses			12,500	0.37
Subtotal conversion costs			1,273,800	37.32
Subtotal direct costs			1,734,000	50.80
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,412,800	41.39
Overhead				
Plant, 20% of conversion costs			254,800	7.46
Administrative, 10% of operating labor			11,900	0.35
Subtotal indirect costs			1,679,500	49.20
Total annual operating cost			3,413,500	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.66	2.44	26.50	435.95

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 2,058,200 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $9,482,000; subtotal direct investment, $5,757,000.
Working capital, $295,900.

Table B-87

LIME SLURRY PROCESS, 200 MW. NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 9482000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	2058200	7800	38100	0.0	4400000	0	4400000	4400000
2	7000	12880000	2058200	7800	38100	0.0	4334200	0	4334200	8734200
3	7000	12880000	2058200	7800	38100	0.0	4268500	0	4268500	13002700
4	7000	12880000	2058200	7800	38100	0.0	4202700	0	4202700	17205400
5	7000	12880000	2058200	7800	38100	0.0	4137000	0	4137000	21342400
6	7000	12880000	2058200	7800	38100	0.0	4071200	0	4071200	25413600
7	7000	12880000	2058200	7800	38100	0.0	4005500	0	4005500	29419100
8	7000	12880000	2058200	7800	38100	0.0	3939700	0	3939700	33358800
9	7000	12880000	2058200	7800	38100	0.0	3874000	0	3874000	37232800
10	7000	12880000	2058200	7800	38100	0.0	3808200	0	3808200	41041000
11	5000	9200000	1470100	5600	27200	0.0	3255200	0	3255200	44296200
12	5000	9200000	1470100	5600	27200	0.0	3189400	0	3189400	47485600
13	5000	9200000	1470100	5600	27200	0.0	3123700	0	3123700	50609300
14	5000	9200000	1470100	5600	27200	0.0	3057900	0	3057900	53667200
15	5000	9200000	1470100	5600	27200	0.0	2992200	0	2992200	56659400
16	3500	6440000	1029100	3900	19000	0.0	2544700	0	2544700	59204100
17	3500	6440000	1029100	3900	19000	0.0	2479000	0	2479000	61683100
18	3500	6440000	1029100	3900	19000	0.0	2413200	0	2413200	64096300
19	3500	6440000	1029100	3900	19000	0.0	2347500	0	2347500	66443800
20	3500	6440000	1029100	3900	19000	0.0	2281700	0	2281700	68725500
21	1500	2760000	441000	1700	8200	0.0	1664900	0	1664900	70390400
22	1500	2760000	441000	1700	8200	0.0	1599100	0	1599100	71989500
23	1500	2760000	441000	1700	8200	0.0	1533400	0	1533400	73522900
24	1500	2760000	441000	1700	8200	0.0	1467600	0	1467600	74990500
25	1500	2760000	441000	1700	8200	0.0	1401900	0	1401900	76392400
26	1500	2760000	441000	1700	8200	0.0	1336100	0	1336100	77728500
27	1500	2760000	441000	1700	8200	0.0	1270400	0	1270400	78998900
28	1500	2760000	441000	1700	8200	0.0	1204600	0	1204600	80203500
29	1500	2760000	441000	1700	8200	0.0	1138900	0	1138900	81342400
30	1500	2760000	441000	1700	8200	0.0	1073100	0	1073100	82415500
TOT	127500	234600000	37488000	142500	694000		82415500	0	82415500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							2.20	0.0	2.20	
MILLS PER KILOWATT-HOUR							3.23	0.0	3.23	
CENTS PER MILLION BTU HEAT INPUT							35.13	0.0	35.13	
DOLLARS PER TON OF SULFUR REMOVED							578.35	0.0	578.35	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							33612500	0	33612500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							2.08	0.0	2.08	
MILLS PER KILOWATT-HOUR							3.06	0.0	3.06	
CENTS PER MILLION BTU HEAT INPUT							33.30	0.0	33.30	
DOLLARS PER TON OF SULFUR REMOVED							549.22	0.0	549.22	

Table B-88. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	287,000	2.8
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	146,000	1.4
First stage sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	3,631,000	35.6
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	2,841,000	27.9
Stack gas reheat (4 direct oil-fired reheaters)	245,000	2.4
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	515,000	5.1
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	1,309,000	12.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	186,000	1.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	547,000	5.4
Construction facilities	485,000	4.8
Subtotal direct investment	10,192,000	100.0
Engineering design and supervision	917,000	9.0
Construction field expense	1,121,000	11.0
Contractor fees	510,000	5.0
Contingency	1,019,000	10.0
Subtotal fixed investment	13,759,000	135.0
Allowance for startup and modifications	1,101,000	10.8
Interest during construction (8%/annum rate)	1,101,000	10.8
Total capital investment	15,961,000	156.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-89. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 1.0% S in fuel;
90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	17.3 M tons	26.00/ton	449,800	7.82
Subtotal raw material			449,800	7.82
Conversion costs				
Operating labor and supervision	14,880 man-hr	8.00/man-hr	119,000	2.07
Utilities				
Fuel oil (No. 6)	2,134,000 gal	0.23/gal	490,800	8.54
Process water	160,500 M gal	0.08/M gal	12,800	0.22
Electricity	53,440,000 kWh	0.018/kWh	961,900	16.74
Maintenance				
Labor and material, .08 x 10,192,000			815,400	14.18
Analyses			24,000	0.42
Subtotal conversion costs			2,423,900	42.17
Subtotal direct costs			2,873,700	49.99
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,378,200	41.37
Overhead				
Plant, 20% of conversion costs			484,800	8.43
Administrative, 10% of operating labor			11,900	0.21
Subtotal indirect costs			2,874,900	50.01
Total annual operating cost			5,748,600	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.14	1.64	18.25	751.45

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $15,961,000; subtotal direct investment, $10,192,000.
Working capital, $479,700.

Table B-90

LIME SLURRY PROCESS, 500 MW. NEW OIL FIRED POWER UNIT, 1.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 15961000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	7700	37300	0.0	7409000	0	7409000	7409000
2	7000	31500000	5033600	7700	37300	0.0	7298300	0	7298300	14707300
3	7000	31500000	5033600	7700	37300	0.0	7187700	0	7187700	21895000
4	7000	31500000	5033600	7700	37300	0.0	7077000	0	7077000	28972000
5	7000	31500000	5033600	7700	37300	0.0	6966400	0	6966400	35938400
6	7000	31500000	5033600	7700	37300	0.0	6855700	0	6855700	42794100
7	7000	31500000	5033600	7700	37300	0.0	6745100	0	6745100	49539200
8	7000	31500000	5033600	7700	37300	0.0	6634400	0	6634400	56173600
9	7000	31500000	5033600	7700	37300	0.0	6523700	0	6523700	62697300
10	7000	31500000	5033600	7700	37300	0.0	6413100	0	6413100	69110400
11	5000	22500000	3595400	5500	26600	0.0	5460500	0	5460500	74570900
12	5000	22500000	3595400	5500	26600	0.0	5349900	0	5349900	79920800
13	5000	22500000	3595400	5500	26600	0.0	5239200	0	5239200	85160000
14	5000	22500000	3595400	5500	26600	0.0	5128600	0	5128600	90288600
15	5000	22500000	3595400	5500	26600	0.0	5017900	0	5017900	95306500
16	3500	15750000	2516800	3800	18600	0.0	4252300	0	4252300	99558800
17	3500	15750000	2516800	3800	18600	0.0	4141700	0	4141700	103700500
18	3500	15750000	2516800	3800	18600	0.0	4031000	0	4031000	107731500
19	3500	15750000	2516800	3600	18600	0.0	3920400	0	3920400	111651900
20	3500	15750000	2516800	3800	18600	0.0	3809700	0	3809700	115461600
21	1500	6750000	1078600	160	8000	0.0	2764900	0	2764900	118226500
22	1500	6750000	1078600	1600	8000	0.0	2654200	0	2654200	120880700
23	1500	6750000	1078600	1600	8000	0.0	2543600	0	2543600	123424300
24	1500	6750000	1078600	1600	8000	0.0	2432900	0	2432900	125857200
25	1500	6750000	1078600	1600	8000	0.0	2322200	0	2322200	128179400
26	1500	6750000	1078600	1600	8000	0.0	2211600	0	2211600	130391000
27	1500	6750000	1078600	1600	8000	0.0	2100900	0	2100900	132491900
28	1500	6750000	1078600	1600	8000	0.0	1990300	0	1990300	134482200
29	1500	6750000	1078600	1600	8000	0.0	1879600	0	1879600	136361800
30	1500	6750000	1078600	1600	8000	0.0	1769000	0	1769000	138130800
TOT	127500	573750000	91683000	139500	679000		138130800	0	138130800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.51	0.0	1.51
MILLS PER KILOWATT-HOUR	2.17	0.0	2.17
CENTS PER MILLION BTU HEAT INPUT	24.08	0.0	24.08
DOLLARS PER TON OF SULFUR REMOVED	990.18	0.0	990.18
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	56505800	0	56505800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.43	0.0	1.43
MILLS PER KILOWATT-HOUR	2.06	0.0	2.06
CENTS PER MILLION BTU HEAT INPUT	22.89	0.0	22.89
DOLLARS PER TON OF SULFUR REMOVED	938.63	0.0	938.63

Table B-91. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	525,000	4.5
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	260,000	2.3
First stage sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	3,631,000	31.3
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	2,841,000	24.5
Stack gas reheat (4 direct oil-fired reheaters)	245,000	2.1
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	515,000	4.5
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	2,286,000	19.7
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	186,000	1.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	547,000	4.7
Construction facilities	552,000	4.8
Subtotal direct investment	11,588,000	100.0
Engineering design and supervision	1,043,000	9.0
Construction field expense	1,275,000	11.0
Contractor fees	579,000	5.0
Contingency	1,159,000	10.0
Subtotal fixed investment	15,644,000	135.0
Allowance for startup and modifications	1,252,000	10.8
Interest during construction (8%/annum rate)	1,252,000	10.8
Total capital investment	18,148,000	156.6

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-92. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	43.3 M tons	24.50/ton	1,060,900	15.48
Subtotal raw material			1,060,900	15.48
Conversion costs				
Operating labor and supervision	16,650 man-hr	8.00/man-hr	133,200	1.94
Utilities				
Fuel oil (No. 6)	2,134,000 gal	0.23/gal	490,800	7.16
Process water	182,500 M gal	0.08/M gal	14,600	0.21
Electricity	53,760,000 kWh	0.018/kWh	967,700	14.12
Maintenance				
Labor and material, .08 × 11,588,000			927,000	13.54
Analyses			28,800	0.42
Subtotal conversion costs			2,562,100	37.39
Subtotal direct costs			3,623,000	52.87
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,704,100	39.46
Overhead				
Plant, 20% of conversion costs			512,400	7.48
Administrative, 10% of operating labor			13,300	0.19
Subtotal indirect costs			3,229,800	47.13
Total annual operating cost			6,852,800	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.36	1.96	21.75	358.22

[a] Basis:

Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $18,148,000; subtotal direct investment, $11,588,000.
Working capital, $619,700.

Table B-93

LIME SLURRY PROCESS, 500 MW. NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 18148000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	19100	93200	0.0	8740700	0	8740700	8740700
2	7000	31500000	5033600	19100	93200	0.0	8614900	0	8614900	17355600
3	7000	31500000	5033600	19100	93200	0.0	8489000	0	8489000	25844600
4	7000	31500000	5033600	19100	93200	0.0	8363200	0	8363200	34207800
5	7000	31500000	5033600	19100	93200	0.0	8237600	0	8237600	42445200
6	7000	31500000	5033600	19100	93200	0.0	8111600	0	8111600	50556800
7	7000	31500000	5033600	19100	93200	0.0	7985800	0	7985800	58542600
8	7000	31500000	5033600	19100	93200	0.0	7859900	0	7859900	66402500
9	7000	31500000	5033600	19100	93200	0.0	7734100	0	7734100	74136600
10	7000	31500000	5033600	19100	93200	0.0	7608300	0	7608300	81744900
11	5000	22500000	3595400	13700	66500	0.0	6434500	0	6434500	88179400
12	5000	22500000	3595400	13700	66500	0.0	6308700	0	6308700	94488100
13	5000	22500000	3595400	13700	66500	0.0	6182900	0	6182900	100671000
14	5000	22500000	3595400	13700	66500	0.0	6057000	0	6057000	106728000
15	5000	22500000	3595400	13700	66500	0.0	5931200	0	5931200	112659200
16	3500	15750000	2516800	9600	46600	0.0	4992500	0	4992500	117651700
17	3500	15750000	2516800	9600	46600	0.0	4866700	0	4866700	122518400
18	3500	15750000	2516800	9600	46600	0.0	4740900	0	4740900	127259300
19	3500	15750000	2516800	9600	46600	0.0	4615000	0	4615000	131874300
20	3500	15750000	2516800	9600	46600	0.0	4489200	0	4489200	136363500
21	1500	6750000	1078600	4100	20000	0.0	3210900	0	3210900	139574400
22	1500	6750000	1078600	4100	20000	0.0	3085100	0	3085100	142659500
23	1500	6750000	1078600	4100	20000	0.0	2959300	0	2959300	145618800
24	1500	6750000	1078600	4100	20000	0.0	2833400	0	2833400	148452200
25	1500	6750000	1078600	4100	20000	0.0	2707600	0	2707600	151159800
26	1500	6750000	1078600	4100	20000	0.0	2581800	0	2581800	153741600
27	1500	6750000	1078600	4100	20000	0.0	2456000	0	2456000	156197600
28	1500	6750000	1078600	4100	20000	0.0	2330200	0	2330200	158527800
29	1500	6750000	1078600	4100	20000	0.0	2204300	0	2204300	160732100
30	1500	6750000	1078600	4100	20000	0.0	2078500	0	2078500	162810600
TOT	127500	573750000	91683000	348500	1697500		162810600	0	162810600	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.78	0.0	1.78	
MILLS PER KILOWATT-HOUR							2.55	0.0	2.55	
CENTS PER MILLION BTU HEAT INPUT							28.38	0.0	28.38	
DOLLARS PER TON OF SULFUR REMOVED							467.18	0.0	467.18	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							66727200	0	66727200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.69	0.0	1.69	
MILLS PER KILOWATT-HOUR							2.43	0.0	2.43	
CENTS PER MILLION BTU HEAT INPUT							27.03	0.0	27.03	
DOLLARS PER TON OF SULFUR REMOVED							445.44	0.0	445.44	

Table B-94. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	716,000	5.6
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	350,000	2.8
First stage sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	3,631,000	28.6
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	2,841,000	22.4
Stack gas reheat (4 direct oil-fired reheaters)	245,000	1.9
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	515,000	4.1
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	3,048,000	24.0
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	186,000	1.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	547,000	4.3
Construction facilities	604,000	4.8
Subtotal direct investment	12,683,000	100.0
Engineering design and supervision	1,141,000	9.0
Construction field expense	1,395,000	11.0
Contractor fees	634,000	5.0
Contingency	1,268,000	10.0
Subtotal fixed investment	17,121,000	135.0
Allowance for startup and modifications	1,370,000	10.8
Interest during construction (8%/annum rate)	1,370,000	10.8
Total capital investment	19,861,000	156.6

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-95. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	69.3 M tons	22.50/ton	1,559,300	20.14
Subtotal raw material			1,559,300	20.14
Conversion costs				
Operating labor and supervision	18,410 man-hr	8.00/man-hr	147,300	1.90
Utilities				
Fuel oil (No. 6)	2,134,000 gal	0.23/gal	490,800	6.34
Process water	204,600 M gal	0.08/M gal	16,400	0.21
Electricity	54,080,000 kWh	0.018/kWh	973,400	12.58
Maintenance				
Labor and material, .08 × 12,683,000			1,014,600	13.10
Analyses			31,700	0.41
Subtotal conversion costs			2,674,200	34.54
Subtotal direct costs			4,233,500	54.68
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,959,300	38.22
Overhead				
Plant, 20% of conversion costs			534,800	6.91
Administrative, 10% of operating labor			14,700	0.19
Subtotal indirect costs			3,508,800	45.32
Total annual operating cost			7,742,300	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.54	2.21	24.58	252.85

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $19,861,000; subtotal direct investment, $12,683,000.
Working capital, $733,800.

Table B-96

LIME SLURRY PROCESS, 500 MW. NEW OIL FIRED POWER UNIT, 4.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 19661000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	30600	149100	0.0	9808500	0	9808500	9808500
2	7000	31500000	5033600	30600	149100	0.0	9670800	0	9670800	19479300
3	7000	31500000	5033600	30600	149100	0.0	9533100	0	9533100	29012400
4	7000	31500000	5033600	30600	149100	0.0	9395400	0	9395400	38407800
5	7000	31500000	5033600	30600	149100	0.0	9257700	0	9257700	47665500
6	7000	31500000	5033600	30600	149100	0.0	9120000	0	9120000	56785500
7	7000	31500000	5033600	30600	149100	0.0	8982300	0	8982300	65767800
8	7000	31500000	5033600	30600	149100	0.0	8844600	0	8844600	74612400
9	7000	31500000	5033600	30600	149100	0.0	8706900	0	8706900	83319300
10	7000	31500000	5033600	30600	149100	0.0	8569200	0	8569200	91888500
11	5000	22500000	3595400	21900	106500	0.0	7215500	0	7215500	99104000
12	5000	22500000	3595400	21900	106500	0.0	7077800	0	7077800	106181800
13	5000	22500000	3595400	21900	106500	0.0	6940100	0	6940100	113121900
14	5000	22500000	3595400	21900	106500	0.0	6802400	0	6802400	119924300
15	5000	22500000	3595400	21900	106500	0.0	6664700	0	6664700	126589000
16	3500	15750000	2516800	15300	74500	0.0	5585500	0	5585500	132174500
17	3500	15750000	2516800	15300	74500	0.0	5447900	0	5447900	137622400
18	3500	15750000	2516800	15300	74500	0.0	5310200	0	5310200	142932600
19	3500	15750000	2516800	15300	74500	0.0	5172500	0	5172500	148105100
20	3500	15750000	2516800	15300	74500	0.0	5034800	0	5034800	153139900
21	1500	6750000	1078600	6600	31900	0.0	3566400	0	3566400	156706300
22	1500	6750000	1078600	6600	31900	0.0	3428700	0	3428700	160135000
23	1500	6750000	1078600	6600	31900	0.0	3291000	0	3291000	163426000
24	1500	6750000	1078600	6600	31900	0.0	3153300	0	3153300	166579300
25	1500	6750000	1078600	6600	31900	0.0	3015600	0	3015600	169594900
26	1500	6750000	1078600	6600	31900	0.0	2877900	0	2877900	172472800
27	1500	6750000	1078600	6600	31900	0.0	2740200	0	2740200	175213000
28	1500	6750000	1078600	6600	31900	0.0	2602500	0	2602500	177815500
29	1500	6750000	1078600	6600	31900	0.0	2464800	0	2464800	180280300
30	1500	6750000	1078600	6600	31900	0.0	2327100	0	2327100	182607400
TOT	127500	573750000	91683000	556000	2715000		182607400	0	182607400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.99	0.0	1.99	
MILLS PER KILOWATT-HOUR							2.86	0.0	2.86	
CENTS PER MILLION BTU HEAT INPUT							31.83	0.0	31.83	
DOLLARS PER TON OF SULFUR REMOVED							327.25	0.0	327.25	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							74929500	0	74929500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.90	0.0	1.90	
MILLS PER KILOWATT-HOUR							2.73	0.0	2.73	
CENTS PER MILLION BTU HEAT INPUT							30.35	0.0	30.35	
DOLLARS PER TON OF SULFUR REMOVED							312.34	0.0	312.34	

Table B-97. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel, 90% SO_2 removal, on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	579,000	4.3
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	293,000	2.2
First stage sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, pumps, and all ductwork between outlet of supplemental fans and the scrubbers)	4,123,000	30.9
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between scrubbers and stack gas plenum)	3,419,000	25.6
Stack gas reheat (4 direct oil-fired reheaters)	263,000	2.0
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,025,000	7.7
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	2,080,000	15.6
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	312,000	2.3
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	609,000	4.6
Construction facilities	635,000	4.8
Subtotal direct investment	13,338,000	100.0
Engineering design and supervision	1,334,000	10.0
Construction field expense	1,734,000	13.0
Contractor fees	934,000	7.0
Contingency	1,467,000	11.0
Subtotal fixed investment	18,807,000	141.0
Allowance for startup and modifications	1,505,000	11.3
Interest during construction (8%/annum rate)	1,505,000	11.3
Total capital investment	21,817,000	163.6

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-98. Lime Slurry Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel, 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	44.3 M tons	24.50/ton	1,085,400	13.56
Subtotal raw material			1,085,400	13.56
Conversion costs				
Operating labor and supervision	16,650 man-hr	8.00/man-hr	133,200	1.66
Utilities				
Fuel oil (No. 6)	3,100,000 gal	0.23/gal	713,000	8.91
Process water	186,300 M gal	0.08/M gal	14,900	0.19
Electricity	56,320,000 kWh	0.018/kWh	1,013,800	12.67
Maintenance				
Labor and material, .08 × 13,338,000			1,067,000	13.34
Analyses			28,800	0.36
Subtotal conversion costs			2,970,700	37.13
Subtotal direct costs			4,056,100	50.69
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,338,000	41.72
Overhead				
Plant, 20% of conversion costs			594,100	7.42
Administrative, 10% of operating labor			13,300	0.17
Subtotal indirect costs			3,945,400	49.31
Total annual operating cost			8,001,500	100.0

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.56	2.29	24.85	409.07

[a] Basis:
Remaining life of power plant, 25 yr.
Oil burned, 5,145,400 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $21,817,000; subtotal direct investment, $13,338,000.
Working capital, $690,400.

Table B-99

LIME SLURRY PROCESS, 500 MW. EXISTING OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 21617000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5145400	19600	95200	0.0	10270500	0	10270500	10270500
7	7000	32200000	5145400	19600	95200	0.0	10089000	0	10089000	20359500
8	7000	32200000	5145400	19600	95200	0.0	9907500	0	9907500	30267000
9	7000	32200000	5145400	19600	95200	0.0	9726000	0	9726000	39993000
10	7000	32200000	5145400	19600	95200	0.0	9544600	0	9544600	49537600
11	5000	23000000	3675300	14000	68000	0.0	8185000	0	8185000	57722400
12	5000	23000000	3675300	14000	68000	0.0	8003500	0	8003500	65725900
13	5000	23000000	3675300	14000	68000	0.0	7822000	0	7822000	73547900
14	5000	23000000	3675300	14000	68000	0.0	7640500	0	7640500	81188400
15	5000	23000000	3675300	14000	68000	0.0	7458900	0	7458900	88647300
16	3500	16100000	2572700	9800	47600	0.0	6364100	0	6364100	95011400
17	3500	16100000	2572700	9800	47600	0.0	6182600	0	6182600	101194000
18	3500	16100000	2572700	9800	47600	0.0	6001100	0	6001100	107195100
19	3500	16100000	2572700	9800	47600	0.0	5819600	0	5819600	113014700
20	3500	16100000	2572700	9800	47600	0.0	5638000	0	5638000	118652700
21	1500	6900000	1102600	4200	20400	0.0	4160400	0	4160400	122813100
22	1500	6900000	1102600	4200	20400	0.0	3978900	0	3978900	126792000
23	1500	6900000	1102600	4200	20400	0.0	3797400	0	3797400	130589400
24	1500	6900000	1102600	4200	20400	0.0	3615800	0	3615800	134205200
25	1500	6900000	1102600	4200	20400	0.0	3434300	0	3434300	137639500
26	1500	6900000	1102600	4200	20400	0.0	3252800	0	3252800	140892300
27	1500	6900000	1102600	4200	20400	0.0	3071300	0	3071300	143963600
28	1500	6900000	1102600	4200	20400	0.0	2889800	0	2889800	146853400
29	1500	6900000	1102600	4200	20400	0.0	2708200	0	2708200	149561600
30	1500	6900000	1102600	4200	20400	0.0	2526700	0	2526700	152088300
TOT	92500	425500000	67993000	259000	1258000		152088300	0	152088300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							2.24	0.0	2.24	
MILLS PER KILOWATT-HOUR							3.29	0.0	3.29	
CENTS PER MILLION BTU HEAT INPUT							35.74	0.0	35.74	
DOLLARS PER TON OF SULFUR REMOVED							587.21	0.0	587.21	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							70126200	0	70126200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							2.09	0.0	2.09	
MILLS PER KILOWATT-HOUR							3.07	0.0	3.07	
CENTS PER MILLION BTU HEAT INPUT							33.41	0.0	33.41	
DOLLARS PER TON OF SULFUR REMOVED							549.15	0.0	549.15	

Table B-100. Lime Slurry Process
Summary of Estimated Fixed Investment[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal, on-site solids disposal)

	Investment, $	Percent of subtotal direct investment
Lime receiving and storage (bins, feeders, conveyors, and elevators)	811,000	4.7
Feed preparation (conveyors, slakers, tanks, agitators, and pumps)	394,000	2.3
First stage sulfur dioxide scrubbers and inlet ducts (4 scrubbers including common feed plenum and pumps)	5,358,000	31.1
Second stage sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fans)	4,247,000	24.7
Stack gas reheat (4 direct oil fired reheaters)	431,000	2.5
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	780,000	4.5
Calcium solids disposal (on-site disposal facilities including slurry disposal pumps, pond, liner, and pond water return pumps)	3,420,000	19.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from the power plant)	244,000	1.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	699,000	4.1
Construction facilities	819,000	4.8
Subtotal direct investment	17,203,000	100.0
Engineering design and supervision	1,376,000	8.0
Construction field expense	1,720,000	10.0
Contractor fees	860,000	5.0
Contingency	1,548,000	9.0
Subtotal fixed investment	22,707,000	132.0
Allowance for startup and modifications	1,817,000	10.6
Interest during construction (8%/annum rate)	1,817,000	10.6
Total capital investment	26,341,000	153.2

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.
Disposal pond located 1 mile from power plant.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-101. Lime Slurry Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; on-site solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime	83.7 M tons	22.00/ton	1,841,400	17.05
Subtotal raw material			1,841,400	17.05
Conversion costs				
Operating labor and supervision	21,950 man-hr	8.00/man-hr	175,600	1.63
Utilities				
Fuel oil (No. 6)	4,128,000 gal	0.23/gal	949,400	8.79
Process water	352,900 M gal	0.08/M gal	28,200	0.26
Electricity	103,940,000 kWh	0.017/kWh	1,767,000	16.37
Maintenance				
Labor and material, .07 x 17,203,000			1,204,200	11.16
Analyses			51,800	0.48
Subtotal conversion costs			4,176,200	38.69
Subtotal direct costs			6,017,600	55.74
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,924,800	36.36
Overhead				
Plant, 20% of conversion costs			835,200	7.74
Administrative, 10% of operating labor			17,600	0.16
Subtotal indirect costs			4,777,600	44.26
Total annual operating cost			10,795,200	100.00

	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	1.11	1.54	17.73	291.84

[a] Basis:

Remaining life of power plant, 30 yr.
Oil burned, 9,731,500 bbl/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $26,341,000; subtotal direct investment, $17,203,000.
Working capital, $1,031,100.

Table B-102

LIME SLURRY PROCESS, 1000 MW. NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS.

FIXED INVESTMENT: $ 26341000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR WASTE SOLIDS	NET REVENUE, $/TON WASTE SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	9731500	37000	180100	0.0	13535500	0	13535500	13535500
2	7000	60900000	9731500	37000	180100	0.0	13352900	0	13352900	26888400
3	7000	60900000	9731500	37000	180100	0.0	13170300	0	13170300	40058700
4	7000	60900000	9731500	37000	180100	0.0	12987700	0	12987700	53046400
5	7000	60900000	9731500	37000	180100	0.0	12805000	0	12805000	65851400
6	7000	60900000	9731500	37000	180100	0.0	12622400	0	12622400	78473800
7	7000	60900000	9731500	37000	180100	0.0	12439800	0	12439800	90913600
8	7000	60900000	9731500	37000	180100	0.0	12257200	0	12257200	103170800
9	7000	60900000	9731500	37000	180100	0.0	12074500	0	12074500	115245300
10	7000	60900000	9731500	37000	180100	0.0	11891900	0	11891900	127137200
11	5000	43500000	6951100	26400	128600	0.0	9925000	0	9925000	137062200
12	5000	43500000	6951100	26400	128600	0.0	9742400	0	9742400	146804600
13	5000	43500000	6951100	26400	128600	0.0	9559700	0	9559700	156364300
14	5000	43500000	6951100	26400	128600	0.0	9377100	0	9377100	165741400
15	5000	43500000	6951100	26400	128600	0.0	9194500	0	9194500	174935900
16	3500	30450000	4865800	18500	90000	0.0	7639200	0	7639200	182575100
17	3500	30450000	4865800	18500	90000	0.0	7456500	0	7456500	190031600
18	3500	30450000	4865800	18500	90000	0.0	7273900	0	7273900	197305500
19	3500	30450000	4865800	18500	90000	0.0	7091300	0	7091300	204396800
20	3500	30450000	4865800	18500	90000	0.0	6908700	0	6908700	211305500
21	1500	13050000	2085300	7900	38600	0.0	4805400	0	4805400	216110900
22	1500	13050000	2085300	7900	38600	0.0	4622800	0	4622800	220733700
23	1500	13050000	2085300	7900	38600	0.0	4440200	0	4440200	225173900
24	1500	13050000	2085300	7900	38600	0.0	4257600	0	4257600	229431500
25	1500	13050000	2085300	7900	38600	0.0	4075000	0	4075000	233506500
26	1500	13050000	2085300	7900	38600	0.0	3892300	0	3892300	237398800
27	1500	13050000	2085300	7900	38600	0.0	3709700	0	3709700	241108500
28	1500	13050000	2085300	7900	38600	0.0	3527100	0	3527100	244635600
29	1500	13050000	2085300	7900	38600	0.0	3344500	0	3344500	247980100
30	1500	13050000	2085300	7900	38600	0.0	3161800	0	3161800	251141900
TOT	127500	1109250000	177252500	673500	3280000		251141900	0	251141900	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.42	0.0	1.42	
MILLS PER KILOWATT-HOUR							1.97	0.0	1.97	
CENTS PER MILLION BTU HEAT INPUT							22.64	0.0	22.64	
DOLLARS PER TON OF SULFUR REMOVED							372.89	0.0	372.89	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							103411900	0	103411900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.36	0.0	1.36	
MILLS PER KILOWATT-HOUR							1.88	0.0	1.88	
CENTS PER MILLION BTU HEAT INPUT							21.66	0.0	21.66	
DOLLARS PER TON OF SULFUR REMOVED							356.72	0.0	356.72	

Table B-103. Magnesia Slurry–Regeneration Process Summary of Estimated Fixed Investment[a]

(200-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 6.5 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	105,000	1.3
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	134,000	1.6
Particulate scrubbers and inlet ducts (2 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	1,761,000	21.2
Sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	1,143,000	13.7
Stack gas reheat (2 indirect steam reheaters)	214,000	2.6
Fans (2 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	327,000	3.9
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	384,000	4.6
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	553,000	6.6
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	643,000	7.7
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	1,787,000	21.5
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	151,000	1.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	166,000	2.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	557,000	6.7
Construction facilities	396,000	4.8
Subtotal direct investment	8,321,000	100.0
Engineering design and supervision	1,082,000	13.0
Construction field expense	1,082,000	13.0
Contractor fees	582,000	7.0
Contingency	915,000	11.0
Subtotal fixed investment	11,982,000	144.0
Allowance for startup and modifications	1,198,000	14.4
Interest during construction (8%/annum rate)	959,000	11.5
Total capital investment	14,139,000	169.9

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Midwest plant location represents projects beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-104. Magnesia Slurry—Regeneration Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW new coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; 45,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	55 tons	26.00/ton	1,400	0.03
Magnesium oxide (98%)	448 tons	155.00/ton	69,400	1.45
Coke	312 tons	15.00/ton	4,700	0.10
Catalyst	736 liters	1.65/liter	1,200	0.03
Subtotal raw material			76,700	1.61
Conversion costs				
Operating labor and supervision	30,440 man-hr	8.00/man-hr	243,500	5.10
Utilities				
Fuel oil (No. 6)	2,190,000 gal	0.23/gal	503,700	10.54
Steam	180,000 M lb	0.80/M lb	144,000	3.01
Heat credit	8,300 MM Btu	-0.60/MM Btu	(5,000)	(0.10)
Process water	902,700 M gal	0.06/M gal	54,200	1.13
Electricity	29,050,000 kWh	0.011/kWh	319,600	6.69
Maintenance				
Labor and material, .08 x 8,321,000			665,700	13.94
Analyses			54,000	1.13
Subtotal conversion costs			1,979,700	41.44
Subtotal direct costs			2,056,400	43.05
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,106,700	44.10
Overhead				
Plant, 20% of conversion costs			395,900	8.29
Administrative and marketing, 11% of conversion costs			217,800	4.56
Subtotal indirect costs			2,720,400	56.95
Total annual operating cost			4,776,800	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	105.68	8.90	3.41	37.09	323.85

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $14,139,000; subtotal direct investment, $8,321,000.
Working capital, $363,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-105

MAGNESIA SLURRY-REGENERATION PROCESS, 200 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 14139000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT EQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	536700	14700	45200	8.00	6247700	361600	5886100	5886100
2	7000	12880000	536700	14700	45200	8.00	6149700	361600	5788100	11674200
3	7000	12880000	536700	14700	45200	8.00	6051700	361600	5690100	17364300
4	7000	12880000	536700	14700	45200	8.00	5953600	361600	5592000	22956300
5	7000	12880000	536700	14700	45200	8.00	5855600	361600	5494000	28450300
6	7000	12880000	536700	14700	45200	8.00	5757600	361600	5396000	33846300
7	7000	12880000	536700	14700	45200	8.00	5659500	361600	5297900	39144200
8	7000	12880000	536700	14700	45200	8.00	5561500	361600	5199900	44344100
9	7000	12880000	536700	14700	45200	8.00	5463500	361600	5101900	49446000
10	7000	12880000	536700	14700	45200	8.00	5365400	361600	5003800	54449800
11	5000	9200000	383300	10500	32300	8.00	4636100	258400	4377700	58827500
12	5000	9200000	383300	10500	32300	8.00	4538100	258400	4279700	63107200
13	5000	9200000	383300	10500	32300	8.00	4440000	258400	4181600	67288800
14	5000	9200000	383300	10500	32300	8.00	4342000	258400	4083600	71372400
15	5000	9200000	383300	10500	32300	8.00	4244000	258400	3985600	75358000
16	3500	6440000	268300	7400	22600	8.00	3647600	180800	3466800	78824800
17	3500	6440000	268300	7400	22600	8.00	3549500	180800	3368700	82193500
18	3500	6440000	268300	7400	22600	8.00	3451500	180800	3270700	85464200
19	3500	6440000	268300	7400	22600	8.00	3353500	180800	3172700	88636900
20	3500	6440000	268300	7400	22600	8.00	3255400	180800	3074600	91711500
21	1500	2760000	115000	3200	9700	8.00	2427800	77600	2350200	94061700
22	1500	2760000	115000	3200	9700	8.00	2329800	77600	2252200	96313900
23	1500	2760000	115000	3200	9700	8.00	2231700	77600	2154100	98468000
24	1500	2760000	115000	3200	9700	8.00	2133700	77600	2056100	100524100
25	1500	2760000	115000	3200	9700	8.00	2035700	77600	1958100	102482200
26	1500	2760000	115000	3200	9700	8.00	1937700	77600	1860100	104342300
27	1500	2760000	115000	3200	9700	8.00	1839600	77600	1762000	106104300
28	1500	2760000	115000	3200	9700	8.00	1741600	77600	1664000	107768300
29	1500	2760000	115000	3200	9700	8.00	1643600	77600	1566000	109334300
30	1500	2760000	115000	3200	9700	8.00	1545500	77600	1467900	110802200
TOT	127500	234600000	9775000	268500	823500		117390200	6586000	110802200	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							12.01	0.67	11.34	
MILLS PER KILOWATT-HOUR							4.60	0.25	4.35	
CENTS PER MILLION BTU HEAT INPUT							50.04	2.81	47.23	
DOLLARS PER TON OF SULFUR REMOVED							437.21	24.54	412.67	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							47694800	2834500	44860300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							11.34	0.68	10.66	
MILLS PER KILOWATT-HOUR							4.35	0.26	4.09	
CENTS PER MILLION BTU HEAT INPUT							47.24	2.80	44.44	
DOLLARS PER TON OF SULFUR REMOVED							413.66	24.59	389.07	

Table B-106. Magnesia Slurry–Regeneration Process Summary of Estimated Fixed Investment[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 6.7 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	116,000	1.4
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	153,000	1.9
Sulfur dioxide scrubbers and ducts (2 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	1,983,000	24.4
Stack gas reheat (2 direct oil-fired reheaters)	129,000	1.6
Fans (2 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	493,000	6.1
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	429,000	5.3
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	610,000	7.5
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	706,000	8.7
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	2,032,000	25.0
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	180,000	2.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	282,000	3.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	620,000	7.6
Construction facilities	387,000	4.8
Subtotal direct investment	8,120,000	100.0
Engineering design and supervision	1,137,000	14.0
Construction field expense	1,218,000	15.0
Contractor fees	731,000	9.0
Contingency	974,000	12.0
Subtotal fixed investment	12,180,000	150.0
Allowance for startup and modifications	1,218,000	15.0
Interest during construction (8%/annum rate)	974,000	12.0
Total capital investment	14,372,000	177.0

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972 ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 20 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-107. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; 46,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	463 tons	155.00/ton	71,800	1.41
Coke	322 tons	15.00/ton	4,800	0.09
Catalyst	760 liters	1.65/liter	1,300	0.03
Subtotal raw material			77,900	1.53
Conversion costs				
Operating labor and supervision	30,440 man-hr	8.00/man-hr	243,500	4.78
Utilities				
Fuel oil (No. 6)	3,783,000 gal	0.23/gal	870,100	17.10
Heat credit	8,600 MM Btu	-0.60/MM Btu	(5,000)	(0.10)
Process water	931,400 M gal	0.06/M gal	55,900	1.10
Electricity	19,500,000 kWh	0.011/kWh	214,500	4.21
Maintenance				
Labor and material, .08 x 8,120,000			649,600	12.76
Analyses			54,000	1.06
Subtotal conversion costs			2,082,600	40.91
Subtotal direct costs			2,160,500	42.44
Indirect Costs				
Average capital charges at 15.9% of total capital investment			2,285,100	44.88
Overhead				
Plant, 20% of conversion costs			416,500	8.18
Administrative and marketing, 11% of conversion costs			229,100	4.50
Subtotal indirect costs			2,930,700	57.56
Total annual operating cost			5,091,200	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	109.25	9.19	3.64	38.28	334.29

[a] Basis:
Remaining life of power plant, 20 yr.
Coal burned, 554,200 tons/yr, 9,500 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $14,372,000; subtotal direct investment, $8,120,000.
Working capital, $382,200.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-108

MAGNESIA SLURRY-REGENERATION PROCESS, 20C MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 14372000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	395800	10900	33300	8.00	5913400	266400	5647000	5647000
12	5000	9500000	395800	10900	33300	8.00	5763900	266400	5497500	11144500
13	5000	9500000	395800	10900	33300	8.00	5614400	266400	5348000	16492500
14	5000	9500000	395800	10900	33300	8.00	5465000	266400	5198600	21691100
15	5000	9500000	395800	10900	33300	8.00	5315500	266400	5049100	26740200
16	3500	6650000	277100	7600	23300	8.00	4637400	186400	4451000	31191200
17	3500	6650000	277100	7600	23300	8.00	4488000	186400	4301600	35492800
18	3500	6650000	277100	7600	23300	8.00	4338500	186400	4152100	39644900
19	3500	6650000	277100	7600	23300	8.00	4189000	186400	4002600	43647500
20	3500	6650000	277100	7600	23300	8.00	4039600	186400	3853200	47500700
21	1500	2850000	118700	3300	10000	8.00	3121200	80000	3041200	50541900
22	1500	2850000	118700	3300	10000	8.00	2971700	80000	2891700	53433600
23	1500	2850000	118700	3300	10000	8.00	2822300	80000	2742300	56175900
24	1500	2850000	118700	3300	10000	8.00	2672800	80000	2592800	58768700
25	1500	2850000	118700	3300	10000	8.00	2523300	80000	2443300	61212000
26	1500	2850000	118700	3300	10000	8.00	2373800	80000	2293800	63505800
27	1500	2850000	118700	3300	10000	8.00	2224400	80000	2144400	65650200
28	1500	2850000	118700	3300	10000	8.00	2074900	80000	1994900	67645100
29	1500	2850000	118700	3300	10000	8.00	1925400	80000	1845400	69490500
30	1500	2850000	118700	3300	10000	8.00	1776000	80000	1696000	71186500
TOT	57500	109250000	4551500	125500	383000		74250500	3064000	71186500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							16.31	0.67	15.64	
MILLS PER KILOWATT-HOUR							6.46	0.27	6.19	
CENTS PER MILLION BTU HEAT INPUT							67.96	2.80	65.16	
DOLLARS PER TON OF SULFUR REMOVED							591.64	24.42	567.22	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							37744300	1638100	36106200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							15.51	0.67	14.84	
MILLS PER KILOWATT-HOUR							6.14	0.27	5.87	
CENTS PER MILLION BTU HEAT INPUT							64.61	2.80	63.81	
DOLLARS PER TON OF SULFUR REMOVED							563.35	24.45	538.90	

Table B-109. Magnesia Slurry—Regeneration Process Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 16.1 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	210,000	1.4
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	270,000	1.7
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	4,469,000	29.0
Stack gas reheat (4 direct oil fired reheaters)	305,000	2.0
Fans (4 fans including ducts and dampers between tie in to existing duct and inlet to supplemental fan)	1,112,000	7.2
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	789,000	5.1
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	1,065,000	6.9
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,211,000	7.9
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	3,608,000	23.4
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	329,000	2.1
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	454,000	2.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	867,000	5.6
Construction facilities	734,000	4.8
Subtotal direct investment	15,423,000	100.0
Engineering design and supervision	1,851,000	12.0
Construction field expense	2,005,000	13.0
Contractor fees	1,080,000	7.0
Contingency	1,697,000	11.0
Subtotal fixed investment	22,056,000	143.0
Allowance for startup and modifications	2,206,000	14.3
Interest during construction (8%/annum rate)	1,764,000	11.4
Total capital investment	26,026,000	168.7

[a] Basis

Stack gas reheat to 175°F by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-110. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 112,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,110 tons	155.00/ton	172,100	1.79
Coke	780 tons	15.00/ton	11,700	0.12
Catalyst	1,840 liters	1.65/liter	3,000	0.03
Subtotal raw material			186,800	1.94
Conversion costs				
Operating labor and supervision	39,200 man-hr	8.00/man-hr	313,600	3.26
Utilities				
Fuel oil (No. 6)	9,160,000 gal	0.23/gal	2,106,800	21.93
Heat credit	20,800 MM Btu	0.60/MM Btu	(12,500)	(0.13)
Process water	2,256,100 M gal	0.04/M gal	90,200	0.94
Electricity	47,230,000 kWh	0.010/kWh	472,300	4.92
Maintenance				
Labor and material, .07 x 15,423,000			1,079,600	11.24
Analyses			102,000	1.06
Subtotal conversion costs			4,152,000	43.22
Subtotal direct costs			4,338,800	45.16
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,982,000	41.45
Overhead				
Plant, 20% of conversion costs			830,400	8.64
Administrative and marketing, 11% of conversion costs			456,700	4.75
Subtotal indirect costs			5,269,100	54.84
Total annual operating cost			9,607,900	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	85.10	7.16	2.75	29.84	260.66

[a] Basis:

Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, \$26,026,000; subtotal direct investment, \$15,423,000.
Working capital, \$768,100.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-111

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 26026000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36900	112900	8.00	12314500	903200	11411300	11411300
7	7000	32200000	1341700	36900	112900	8.00	12098000	903200	11194800	22606100
8	7000	32200000	1341700	36900	112900	8.00	11881500	903200	10978300	33584400
9	7000	32200000	1341700	36900	112900	8.00	11664900	903200	10761700	44346100
10	7000	32200000	1341700	36900	112900	8.00	11448400	903200	10545200	54891300
11	5000	23000000	958300	26300	80600	8.00	9824100	644800	9179300	64070600
12	5000	23000000	958300	26300	80600	8.00	9607500	644800	8962700	73033300
13	5000	23000000	958300	26300	80600	8.00	9391000	644800	8746200	81779500
14	5000	23000000	958300	26300	80600	8.00	9174500	644800	8529700	90309200
15	5000	23000000	958300	26300	80600	8.00	8958000	644800	8313200	98622400
16	3500	16100000	670800	18400	56500	8.00	7647400	452000	7195400	105817800
17	3500	16100000	670800	18400	56500	8.00	7430900	452000	6978900	112796700
18	3500	16100000	670800	18400	56500	8.00	7214400	452000	6762400	119559100
19	3500	16100000	670800	18400	56500	8.00	6997800	452000	6545800	126104900
20	3500	16100000	670800	18400	56500	8.00	6781300	452000	6329300	132434200
21	1500	6900000	287500	7900	24200	8.00	5006700	193600	4813100	137247300
22	1500	6900000	287500	7900	24200	8.00	4790200	193600	4596600	141843900
23	1500	6900000	287500	7900	24200	8.00	4573600	193600	4380000	146223900
24	1500	6900000	287500	7900	24200	8.00	4357100	193600	4163500	150387400
25	1500	6900000	287500	7900	24200	8.00	4140600	193600	3947000	154334400
26	1500	6900000	287500	7900	24200	8.00	3924000	193600	3730400	158064800
27	1500	6900000	287500	7900	24200	8.00	3707500	193600	3513900	161578700
28	1500	6900000	287500	7900	24200	8.00	3491000	193600	3297400	164876100
29	1500	6900000	287500	7900	24200	8.00	3274500	193600	3080900	167957000
30	1500	6900000	287500	7900	24200	8.00	3057900	193600	2864300	170821300
TOT	92500	425500000	17729000	487000	1492000		152757300	11936000	170821300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.31	0.67	9.64	
MILLS PER KILOWATT-HOUR							3.95	0.26	3.69	
CENTS PER MILLION BTU HEAT INPUT							42.95	2.80	40.15	
DOLLARS PER TON OF SULFUR REMOVED							375.27	24.51	350.76	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							84179100	5886900	78292200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.63	0.68	8.95	
MILLS PER KILOWATT-HOUR							3.69	0.26	3.43	
CENTS PER MILLION BTU HEAT INPUT							40.11	2.81	37.30	
DOLLARS PER TON OF SULFUR REMOVED							350.31	24.50	325.81	

Table B-112. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 2.0% S in fuel,
90% SO_2 removal; 9.0 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	132,000	0.9
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	166,000	1.2
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,966,000	27.9
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	2,592,000	18.3
Stack gas reheat (4 indirect steam reheaters)	509,000	3.6
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	741,000	5.2
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	484,000	3.4
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	684,000	4.8
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	788,000	5.6
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	2,222,000	15.6
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	190,000	1.3
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	269,000	1.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	783,000	5.5
Construction facilities	676,000	4.8
Subtotal direct investment	14,202,000	100.0
Engineering design and supervision	1,562,000	11.0
Construction field expense	1,562,000	11.0
Contractor fees	710,000	5.0
Contingency	1,420,000	10.0
Subtotal fixed investment	19,456,000	137.0
Allowance for startup and modifications	1,946,000	13.7
Interest during construction (8%/annum rate)	1,556,000	11.0
Total capital investment	22,958,000	161.7

[a] Basis:
Stack gas reheat to 175°F by indirect steam reheat.
Midwest plant location represents projects beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-113. Magnesia Slurry—Regeneration Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; 63,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	77 tons	26.00/ton	2,000	0.03
Magnesium oxide (98%)	620 tons	155.00/ton	96,100	1.27
Coke	436 tons	15.00/ton	6,500	0.09
Catalyst	1,029 liters	1.65/liter	1,700	0.02
Subtotal raw material			106,300	1.41
Conversion costs				
Operating labor and supervision	32,520 man-hr	8.00/man-hr	260,200	3.46
Utilities				
Fuel oil (No. 6)	3,061,000 gal	0.23/gal	704,000	9.36
Steam	440,000 M lb	0.70/M lb	308,000	4.09
Heat credit	11,600 MM Btu	-0.60/MM Btu	(7,000)	(0.09)
Process water	1,350,000 M gal	0.05/M gal	67,500	0.90
Electricity	63,270,000 kWh	0.010/kWh	632,700	8.41
Maintenance				
Labor and material, .07 x 14,202,000			994,100	13.21
Analyses			91,200	1.21
Subtotal conversion costs			3,050,700	40.55
Subtotal direct costs			3,157,000	41.96
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,420,700	45.47
Overhead				
Plant, 20% of conversion costs			610,100	8.11
Administrative and marketing, 11% of conversion costs			335,600	4.46
Subtotal indirect costs			4,366,400	58.04
Total annual operating cost			7,523,400	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	119.23	5.73	2.15	23.88	365.04

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $22,958,000; subtotal direct investment, $14,202,000.
Working capital, $558,400.
Investment and operating cost for disposal of fly ash excluded.

Table B-114

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 2.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 22958000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	20600	63100	8.00	9912100	504800	9407300	9407300
2	7000	31500000	1312500	20600	63100	8.00	9752900	504800	9248100	18655400
3	7000	31500000	1312500	20600	63100	8.00	9593700	504800	9088900	27744300
4	7000	31500000	1312500	20600	63100	8.00	9434500	504800	8929700	36674000
5	7000	31500000	1312500	20600	63100	8.00	9275300	504800	8770500	45444500
6	7000	31500000	1312500	20600	63100	8.00	9116200	504800	8611400	54055900
7	7000	31500000	1312500	20600	63100	8.00	8957000	504800	8452200	62508100
8	7000	31500000	1312500	20600	63100	8.00	8797800	504800	8293000	70801100
9	7000	31500000	1312500	20600	63100	8.00	8638600	504800	8133800	78934900
10	7000	31500000	1312500	20600	63100	8.00	8479400	504800	7974600	86909500
11	5000	22500000	937500	14700	45100	8.00	7326400	360800	6965600	93875100
12	5000	22500000	937500	14700	45100	8.00	7167300	360800	6806500	100681600
13	5000	22500000	937500	14700	45100	8.00	7008100	360800	6647300	107328900
14	5000	22500000	937500	14700	45100	8.00	6848900	360800	6488100	113817000
15	5000	22500000	937500	14700	45100	8.00	6689700	360800	6328900	120145900
16	3500	15750000	656200	10300	31500	8.00	5751600	252000	5499600	125645500
17	3500	15750000	656200	10300	31500	8.00	5592400	252000	5340400	130985900
18	3500	15750000	656200	10300	31500	8.00	5433300	252000	5181300	136167200
19	3500	15750000	656200	10300	31500	8.00	5274100	252000	5022100	141189300
20	3500	15750000	656200	10300	31500	8.00	5114900	252000	4862900	146052200
21	1500	6750000	281200	4400	13500	8.00	3827200	108000	3719200	149771400
22	1500	6750000	281200	4400	13500	8.00	3668000	108000	3560000	153331400
23	1500	6750000	281200	4400	13500	8.00	3508900	108000	3400900	156732300
24	1500	6750000	281200	4400	13500	8.00	3349700	108000	3241700	159974000
25	1500	6750000	281200	4400	13500	8.00	3190500	108000	3082500	163056500
26	1500	6750000	281200	4400	13500	8.00	3031300	108000	2923300	165979800
27	1500	6750000	281200	4400	13500	8.00	2872100	108000	2764100	168743900
28	1500	6750000	281200	4400	13500	8.00	2712900	108000	2604900	171348800
29	1500	6750000	281200	4400	13500	8.00	2553800	108000	2445800	173794600
30	1500	6750000	281200	4400	13500	8.00	2394600	108000	2286600	176081200
TOT	127500	573750000	23905500	375000	1149000		185273200	9192000	176081200	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	7.75	0.38	7.37
MILLS PER KILOWATT-HOUR	2.91	0.15	2.76
CENTS PER MILLION BTU HEAT INPUT	32.29	1.60	30.69
DOLLARS PER TON OF SULFUR REMOVED	494.06	24.51	469.55
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	75460000	3956400	71503600
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	7.34	0.39	6.95
MILLS PER KILOWATT-HOUR	2.75	0.14	2.61
CENTS PER MILLION BTU HEAT INPUT	30.56	1.60	28.96
DOLLARS PER TON OF SULFUR REMOVED	467.53	24.51	443.02

Table B-115. Magnesia Slurry–Regeneration Process Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 15.8 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	192,000	1.2
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	238,000	1.5
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,966,000	24.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	2,592,000	15.9
Stack gas reheat (4 indirect steam reheaters)	509,000	3.1
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	741,000	4.5
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	711,000	4.3
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	972,000	5.9
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,108,000	6.8
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	3,197,000	19.6
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	278,000	1.7
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	269,000	1.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	783,000	4.8
Construction facilities	778,000	4.8
Subtotal direct investment	16,334,000	100.0
Engineering design and supervision	1,797,000	11.0
Construction field expense	1,797,000	11.0
Contractor fees	817,000	5.0
Contingency	1,633,000	10.0
Subtotal fixed investment	22,378,000	137.0
Allowance for startup and modifications	2,238,000	13.7
Interest during construction (8%/annum rate)	1,790,000	11.0
Total capital investment	26,406,000	161.7

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.
Midwest plant location represents projects beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-116. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; 110,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	134 tons	26.00/ton	3,500	0.04
Magnesium oxide (98%)	1,086 tons	155.00/ton	168,300	1.83
Coke	763 tons	15.00/ton	11,400	0.12
Catalyst	1,800 liters	1.65/liter	3,000	0.03
Subtotal raw material			186,200	2.02
Conversion costs				
Operating labor and supervision	39,200 man-hr	8.00/man-hr	313,600	3.40
Utilities				
Fuel oil (No. 6)	5,356,000 gal	0.23/gal	1,231,900	13.39
Steam	440,000 M lb	0.70/M lb	308,000	3.34
Heat credit	20,300 MM Btu	-0.60/MM Btu	(12,200)	(0.13)
Process water	2,207,500 M gal	0.04/M gal	88,300	0.96
Electricity	71,060,000 kWh	0.010/kWh	710,600	7.71
Maintenance				
Labor and material, .07 x 16,334,000			1,143,400	12.41
Analyses			102,000	1.11
Subtotal conversion costs			3,885,600	42.19
Subtotal direct costs			4,071,800	44.21
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,934,500	42.71
Overhead				
Plant, 20% of conversion costs			777,100	8.44
Administrative and marketing, 11% of conversion costs			427,400	4.64
Subtotal indirect costs			5,139,000	55.79
Total annual operating cost			9,210,800	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	83.43	7.02	2.63	29.24	255.43

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $26,406,000; subtotal direct investment, $16,334,000.
Working capital, $721,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-117

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 26406000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	36100	110400	8.00	11957900	883200	11074700	11074700
2	7000	31500000	1312500	36100	110400	8.00	11774900	883200	10891700	21966400
3	7000	31500000	1312500	36100	110400	8.00	11591800	883200	10708600	32675000
4	7000	31500000	1312500	36100	110400	8.00	11408700	883200	10525500	43200500
5	7000	31500000	1312500	36100	110400	8.00	11225600	883200	10342400	53542900
6	7000	31500000	1312500	36100	110400	8.00	11042500	883200	10159300	63702200
7	7000	31500000	1312500	36100	110400	8.00	10859500	883200	9976300	73678500
8	7000	31500000	1312500	36100	110400	8.00	10676400	883200	9793200	83471700
9	7000	31500000	1312500	36100	110400	8.00	10493300	883200	9610100	93081800
10	7000	31500000	1312500	36100	110400	8.00	10310200	883200	9427000	102508800
11	5000	22500000	937500	25800	78900	8.00	8827600	631200	8196400	110705200
12	5000	22500000	937500	25800	78900	8.00	8644600	631200	8013400	118718600
13	5000	22500000	937500	25800	78900	8.00	8461500	631200	7830300	126548900
14	5000	22500000	937500	25800	78900	8.00	8278400	631200	7647200	134196100
15	5000	22500000	937500	25800	78900	8.00	8095300	631200	7464100	141660200
16	3500	15750000	656200	18000	55200	8.00	6897800	441600	6456200	148116400
17	3500	15750000	656200	18000	55200	8.00	6714700	441600	6273100	154389500
18	3500	15750000	656200	18000	55200	8.00	6531700	441600	6090100	160479600
19	3500	15750000	656200	18000	55200	8.00	6348600	441600	5907000	166386600
20	3500	15750000	656200	18000	55200	8.00	6165500	441600	5723900	172110500
21	1500	6750000	281200	7700	23700	8.00	4526300	189600	4336700	176447200
22	1500	6750000	281200	7700	23700	8.00	4343200	189600	4153600	180600900
23	1500	6750000	281200	7700	23700	8.00	4160200	189600	3970600	184571400
24	1500	6750000	281200	7700	23700	8.00	3977100	189600	3787500	188358900
25	1500	6750000	281200	7700	23700	8.00	3794000	189600	3604400	191963300
26	1500	6750000	281200	7700	23700	8.00	3610900	189600	3421300	195384600
27	1500	6750000	281200	7700	23700	8.00	3427800	189600	3238200	198622800
28	1500	6750000	281200	7700	23700	8.00	3244700	189600	3055100	201677900
29	1500	6750000	281200	7700	23700	8.00	3061700	189600	2872100	204550000
30	1500	6750000	281200	7700	23700	8.00	2878600	189600	2689000	207239000
TOT	127500	573750000	23905500	657000	2011500		223331000	16092000	207239000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							9.34	0.67	8.67	
MILLS PER KILOWATT-HOUR							3.50	0.25	3.25	
CENTS PER MILLION BTU HEAT INPUT							38.92	2.80	36.12	
DOLLARS PER TON OF SULFUR REMOVED							339.93	24.50	315.43	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							91172800	6923300	84249500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							8.86	0.67	8.19	
MILLS PER KILOWATT-HOUR							3.32	0.25	3.07	
CENTS PER MILLION BTU HEAT INPUT							36.93	2.81	34.12	
DOLLARS PER TON OF SULFUR REMOVED							322.28	24.47	297.81	

Table B-118. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; 22.5 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	244,000	1.3
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	299,000	1.6
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,966,000	21.8
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	2,592,000	14.3
Stack gas reheat (4 indirect steam reheaters)	509,000	2.8
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	741,000	4.1
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	910,000	5.0
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	1,218,000	6.7
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,378,000	7.6
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	4,031,000	22.2
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	354,000	2.0
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	269,000	1.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	783,000	4.3
Construction facilities	865,000	4.8
Subtotal direct investment	18,159,000	100.0
Engineering design and supervision	1,997,000	11.0
Construction field expense	1,997,000	11.0
Contractor fees	908,000	5.0
Contingency	1,816,000	10.0
Subtotal fixed investment	24,877,000	137.0
Allowance for startup and modifications	2,488,000	13.7
Interest during construction (8%/annum rate)	1,990,000	11.0
Total capital investment	29,355,000	161.7

[a] Basis:
Stack gas reheat to 175 °F by indirect steam reheat.
Midwest plant location represents projects beginning mid-1972 ending mid-1975 Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-119. Magnesia Slurry- Regeneration Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; 157,800 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	192 tons	26.00/ton	5,000	0.05
Magnesium oxide (98%)	1,551 tons	155.00/ton	240,400	2.23
Coke	1,090 tons	15.00/ton	16,400	0.15
Catalyst	2,571 liters	1.65/liter	4,200	0.04
Subtotal raw material			266,000	2.47
Conversion costs				
Operating labor and supervision	45,880 man-hr	8.00/man-hr	367,000	3.41
Utilities				
Fuel oil (No. 6)	7,652,000 gal	0.23/gal	1,760,000	16.35
Steam	440,000 M lb	0.70/M lb	308,000	2.86
Heat credit	29,000 MM Btu	-0.60/MM Btu	(17,400)	(0.16)
Process water	3,063,900 M gal	0.03/M gal	91,900	0.85
Electricity	78,850,000 kWh	0.010/kWh	788,500	7.32
Maintenance				
Labor and material, .07 x 18,159,000			1,271,100	11.80
Analyses			109,200	1.01
Subtotal conversion costs			4,678,300	43.44
Subtotal direct costs			4,944,300	45.91
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,373,900	40.62
Overhead				
Plant, 20% of conversion costs			935,700	8.69
Administrative and marketing, 11% of conversion costs			514,600	4.78
Subtotal indirect costs			5,824,200	54.09
Total annual operating cost			10,768,500	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	68.24	8.20	3.08	34.19	209.02

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $29,355,000; subtotal direct investment, $18,159,000.
Working capital, $876,200.
Investment and operating cost for disposal of fly ash excluded.

Table B-120

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 5.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 29355000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	51500	157800	8.00	13822400	1262400	12560000	12560000
2	7000	31500000	1312500	51500	157800	8.00	13618900	1262400	12356500	24916500
3	7000	31500000	1312500	51500	157800	8.00	13415400	1262400	12153000	37069500
4	7000	31500000	1312500	51500	157800	8.00	13211900	1262400	11949500	49019000
5	7000	31500000	1312500	51500	157800	8.00	13008300	1262400	11765900	60764900
6	7000	31500000	1312500	51500	157800	8.00	12804800	1262400	11542400	72307300
7	7000	31500000	1312500	51500	157800	8.00	12601300	1262400	11338900	83646200
8	7000	31500000	1312500	51500	157800	8.00	12397700	1262400	11135300	94781500
9	7000	31500000	1312500	51500	157800	8.00	12194200	1262400	10931800	105713300
10	7000	31500000	1312500	51500	157800	8.00	11990700	1262400	10728300	116441600
11	5000	22500000	937500	36800	112700	8.00	10194600	901600	9293000	125734600
12	5000	22500000	937500	36800	112700	8.00	9991000	901600	9089400	134824000
13	5000	22500000	937500	36800	112700	8.00	9787500	901600	8885900	143709900
14	5000	22500000	937500	36800	112700	8.00	9584000	901600	8682400	152392300
15	5000	22500000	937500	36800	112700	8.00	9380400	901600	8478800	160871100
16	3500	15750000	656200	25800	78900	8.00	7937900	631200	7306700	168177800
17	3500	15750000	656200	25800	78900	8.00	7734400	631200	7103200	175281000
18	3500	15750000	656200	25800	78900	8.00	7530900	631200	6899700	182180700
19	3500	15750000	656200	25800	78900	8.00	7327300	631200	6696100	188876800
20	3500	15750000	656200	25800	78900	8.00	7123800	631200	6492600	195369400
21	1500	6750000	281200	11000	33800	8.00	5151100	270400	4880700	200250100
22	1500	6750000	281200	11000	33800	8.00	4947600	270400	4677200	204927300
23	1500	6750000	281200	11000	33800	8.00	4744000	270400	4473600	209400900
24	1500	6750000	281200	11000	33800	8.00	4540500	270400	4270100	213671000
25	1500	6750000	281200	11000	33800	8.00	4337000	270400	4066600	217737600
26	1500	6750000	281200	11000	33800	8.00	4133400	270400	3863000	221600600
27	1500	6750000	281200	11000	33800	8.00	3929900	270400	3659500	225260100
28	1500	6750000	281200	11000	33800	8.00	3726400	270400	3456000	228716100
29	1500	6750000	281200	11000	33800	8.00	3522900	270400	3252500	231968600
30	1500	6750000	281200	11000	33800	8.00	3319300	270400	3068900	235017500
TOT	127500	573750000	23905500	938000	2874000		258009500	22992000	235017500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.79	0.96	9.83	
MILLS PER KILOWATT-HOUR							4.05	0.36	3.69	
CENTS PER MILLION BTU HEAT INPUT							44.97	4.01	40.96	
DOLLARS PER TON OF SULFUR REMOVED							275.06	24.51	250.55	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							105516200	9894300	95621900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							10.26	0.96	9.30	
MILLS PER KILOWATT-HOUR							3.85	0.36	3.49	
CENTS PER MILLION BTU HEAT INPUT							42.74	4.01	38.73	
DOLLARS PER TON OF SULFUR REMOVED							261.37	24.51	236.86	

Table B-121. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 31.6 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	329,000	1.4
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	414,000	1.8
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	6,774,000	28.9
Stack gas reheat (4 direct oil-fired reheaters)	543,000	2.3
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,685,000	7.2
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	1,253,000	5.3
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	1,625,000	6.9
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,824,000	7.8
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	5,583,000	23.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	519,000	2.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	652,000	2.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	1,119,000	4.8
Construction facilities	1,116,000	4.8
Subtotal direct investment	23,436,000	100.0
Engineering design and supervision	2,578,000	11.0
Construction field expense	2,812,000	12.0
Contractor fees	1,641,000	7.0
Contingency	2,344,000	10.0
Subtotal fixed investment	32,811,000	140.0
Allowance for startup and modifications	3,281,000	14.0
Interest during construction (8%/annum rate)	2,625,000	11.2
Total capital investment	38,717,000	165.2

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Remaining life of power unit, 25 yr.

Investment requirements for removal and disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-122. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 220,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	2,150 tons	155.00/ton	333,300	2.15
Coke	1,526 tons	15.00/ton	22,900	0.15
Catalyst	3,600 liters	1.65/liter	5,900	0.04
Subtotal raw material			362,100	2.34
Conversion costs				
Operating labor and supervision	47,960 man-hr	8.00/man-hr	383,700	2.48
Utilities				
Fuel oil (No. 6)	17,922,000 gal	0.23/gal	4,122,100	26.62
Heat credit	40,600 MM Btu	-0.60/MM Btu	(24,400)	(0.16)
Process water	4,413,900 M gal	0.03/M gal	132,400	0.86
Electricity	92,430,000 kWh	0.009/kWh	831,900	5.37
Maintenance				
Labor and material, .06 x 23,436,000			1,406,200	9.08
Analyses			168,000	1.09
Subtotal conversion costs			7,019,900	45.34
Subtotal direct costs			7,382,000	47.68
Indirect Costs				
Average capital charges at 15.3% of total capital investment			5,923,700	38.26
Overhead				
Plant, 20% of conversion costs			1,404,000	9.07
Administrative and marketing, 11% of conversion costs			772,200	4.99
Subtotal indirect costs			8,099,900	52.32
Total annual operating cost			15,481,900	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	70.09	5.90	2.21	24.57	214.64

[a] Basis:

Remaining life of power plant, 25 yr.
Coal burned, 2,625,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $38,717,000; subtotal direct investment, $23,436,000.
Working capital, $1,307,600.
Investment and operating cost for removal and disposal of fly ash excluded.

Table B-123

MAGNESIA SLURRY-REGENERATION PROCESS, 1000 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 38717000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	2625000	72100	220900	8.00	19508500	1767200	17741300	17741300
7	7000	63000000	2625000	72100	220900	8.00	19186400	1767200	17419200	35160500
8	7000	63000000	2625000	72100	220900	8.00	18864300	1767200	17097100	52257600
9	7000	63000000	2625000	72100	220900	8.00	18542100	1767200	16774900	69032500
10	7000	63000000	2625000	72100	220900	8.00	18220000	1767200	16452800	85485300
11	5000	45000000	1875000	51500	157800	8.00	15422200	1262400	14159800	99645100
12	5000	45000000	1875000	51500	157800	8.00	15100100	1262400	13837700	113482800
13	5000	45000000	1875000	51500	157800	8.00	14777900	1262400	13515500	126998300
14	5000	45000000	1875000	51500	157800	8.00	14455800	1262400	13193400	140191700
15	5000	45000000	1875000	51500	157800	8.00	14133700	1262400	12871300	153063000
16	3500	31500000	1312500	36100	110400	8.00	11906200	883200	11023000	164086000
17	3500	31500000	1312500	36100	110400	8.00	11584100	883200	10700900	174786900
18	3500	31500000	1312500	36100	110400	8.00	11262000	883200	10378800	185165700
19	3500	31500000	1312500	36100	110400	8.00	10939900	883200	10056700	195222400
20	3500	31500000	1312500	36100	110400	8.00	10617700	883200	9734500	204956900
21	1500	13500000	562500	15500	47300	8.00	7627900	378400	7249500	212206400
22	1500	13500000	562500	15500	47300	8.00	7305800	378400	6927400	219133800
23	1500	13500000	562500	15500	47300	8.00	6983600	378400	6605200	225739000
24	1500	13500000	562500	15500	47300	8.00	6661500	378400	6283100	232022100
25	1500	13500000	562500	15500	47300	8.00	6339400	378400	5961000	237983100
26	1500	13500000	562500	15500	47300	8.00	6017200	378400	5638800	243621900
27	1500	13500000	562500	15500	47300	8.00	5695100	378400	5316700	248938600
28	1500	13500000	562500	15500	47300	8.00	5373000	378400	4994600	253933200
29	1500	13500000	562500	15500	47300	8.00	5050900	378400	4672500	258605700
30	1500	13500000	562500	15500	47300	8.00	4728700	378400	4350300	262956000
TOT	92500	832500000	34687500	953500	2918500		286304000	23348000	262956000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							8.25	0.67	7.58	
MILLS PER KILOWATT-HOUR							3.10	0.26	2.84	
CENTS PER MILLION BTU HEAT INPUT							34.39	2.80	31.59	
DOLLARS PER TON OF SULFUR REMOVED							300.27	24.49	275.78	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							132674100	11517900	121156200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							7.75	0.67	7.08	
MILLS PER KILOWATT-HOUR							2.91	0.25	2.66	
CENTS PER MILLION BTU HEAT INPUT							32.31	2.81	29.50	
DOLLARS PER TON OF SULFUR REMOVED							282.23	24.51	257.72	

Table B-124. Magnesia Slurry–Regeneration Process Summary of Estimated Fixed Investment[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 30.5 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	299,000	1.2
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	363,000	1.5
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	5,850,000	23.8
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	3,901,000	15.9
Stack gas reheat (4 indirect steam reheaters)	897,000	3.6
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	1,115,000	4.5
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	1,121,000	4.5
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	1,474,000	6.0
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,657,000	6.7
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	4,907,000	20.0
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	435,000	1.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	384,000	1.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	1,006,000	4.1
Construction facilities	1,170,000	4.8
Subtotal direct investment	24,579,000	100.0
Engineering design and supervision	2,458,000	10.0
Construction field expense	2,458,000	10.0
Contractor fees	1,229,000	5.0
Contingency	2,212,000	9.0
Subtotal fixed investment	32,936,000	134.0
Allowance for startup and modifications	3,294,000	13.4
Interest during construction (8%/annum rate)	2,635,000	10.7
Total capital investment	38,865,000	158.1

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Midwest plant location represents projects beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-125. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 213,500 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	259 tons	26.00/ton	6,700	0.05
Magnesium oxide (98%)	2,078 tons	155.00/ton	322,100	2.25
Coke	1,475 tons	15.00/ton	22,100	0.15
Catalyst	3,480 liters	1.65/liter	5,700	0.04
Subtotal raw material			356,600	2.49
Conversion costs				
Operating labor and supervision	47,960 man-hr	8.00/man-hr	383,700	2.67
Utilities				
Fuel oil (No. 6)	10,356,000 gal	0.23/gal	2,381,900	16.60
Steam	850,000 M lb	0.60/M lb	510,000	3.55
Heat credit	39,300 MM Btu	-0.60/MM Btu	(23,600)	(0.16)
Process water	4,267,000 M gal	0.03/M gal	128,000	0.89
Electricity	137,390,000 kWh	0.009/kWh	1,236,500	8.62
Maintenance				
Labor and material, .06 x 24,579,000			1,474,700	10.28
Analyses			168,000	1.17
Subtotal conversion costs			6,259,200	43.62
Subtotal direct costs			6,615,800	46.11
Indirect Costs				
Average capital charges at 14.9% of total capital investment			5,790,900	40.36
Overhead				
Plant, 20% of conversion costs			1,251,800	8.73
Administrative and marketing, 11% of conversion costs			688,500	4.80
Subtotal indirect costs			7,731,200	53.89
Total annual operating cost			14,347,000	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	67.20	5.65	2.05	23.56	205.78

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $38,865,000; subtotal direct investment, $24,579,000.
Working capital, $1,172,400.
Investment and operating cost for disposal of fly ash excluded.

Table B-126

MAGNESIA SLURRY-REGENERATION PROCESS, 1000 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 38865000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2537500	69700	213500	8.00	18390200	1708000	16682200	16682200
2	7000	60900000	2537500	69700	213500	8.00	18120800	1708000	16412800	33095000
3	7000	60900000	2537500	69700	213500	8.00	17851300	1708000	16143300	49238300
4	7000	60900000	2537500	69700	213500	8.00	17581800	1708000	15873800	65112100
5	7000	60900000	2537500	69700	213500	8.00	17312400	1708000	15604600	80716500
6	7000	60900000	2537500	69700	213500	8.00	17042900	1708000	15334900	96051400
7	7000	60900000	2537500	69700	213500	8.00	16773400	1708000	15065400	111116800
8	7000	60900000	2537500	69700	213500	8.00	16504000	1708000	14796000	125912800
9	7000	60900000	2537500	69700	213500	8.00	16234500	1708000	14526500	140439300
10	7000	60900000	2537500	69700	213500	8.00	15965000	1708000	14257000	154696300
11	5000	43500000	1812500	49800	152500	8.00	13515700	1220000	12295700	166992000
12	5000	43500000	1812500	49800	152500	8.00	13246200	1220000	12026200	179018200
13	5000	43500000	1812500	49800	152500	8.00	12976800	1220000	11756800	190775000
14	5000	43500000	1812500	49800	152500	8.00	12707300	1220000	11487300	202262300
15	5000	43500000	1812500	49800	152500	8.00	12437800	1220000	11217800	213480100
16	3500	30450000	1268700	34900	106800	8.00	10483100	854400	9628700	223108800
17	3500	30450000	1268700	34900	106800	8.00	10213600	854400	9359200	232468000
18	3500	30450000	1268700	34900	106800	8.00	9944100	854400	9089700	241557700
19	3500	30450000	1268700	34900	106800	8.00	9674700	854400	8820300	250378000
20	3500	30450000	1268700	34900	106800	8.00	9405200	854400	8550800	258928800
21	1500	13050000	543700	14900	45800	8.00	6755700	366400	6389300	265318100
22	1500	13050000	543700	14900	45800	8.00	6486300	366400	6119900	271438000
23	1500	13050000	543700	14900	45800	8.00	6216800	366400	5850400	277288400
24	1500	13050000	543700	14900	45800	8.00	5947300	366400	5580900	282869300
25	1500	13050000	543700	14900	45800	8.00	5677900	366400	5311500	288180800
26	1500	13050000	543700	14900	45800	8.00	5408400	366400	5042000	293222800
27	1500	13050000	543700	14900	45800	8.00	5139000	366400	4772600	297995400
28	1500	13050000	543700	14900	45800	8.00	4869500	366400	4503100	302498500
29	1500	13050000	543700	14900	45800	8.00	4600000	366400	4233600	306732100
30	1500	13050000	543700	14900	45800	8.00	4330600	366400	3964200	310696300
TOT	127500	1109250000	46218000	1269500	3889500		341812300	31116000	310696300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							7.40	0.68	6.72	
MILLS PER KILOWATT-HOUR							2.68	0.24	2.44	
CENTS PER MILLION BTU HEAT INPUT							30.81	2.80	28.01	
DOLLARS PER TON OF SULFUR REMOVED							269.25	24.51	244.74	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							140196000	13388000	126808000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							7.05	0.67	6.38	
MILLS PER KILOWATT-HOUR							2.56	0.25	2.31	
CENTS PER MILLION BTU HEAT INPUT							29.37	2.80	26.57	
DOLLARS PER TON OF SULFUR REMOVED							256.63	24.51	232.12	

Table B-127. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; 14.0 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	192,000	1.2
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	238,000	1.5
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,966,000	25.1
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	2,592,000	16.4
Stack gas reheat (4 indirect steam reheaters)	509,000	3.2
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	706,000	4.5
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	656,000	4.1
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	902,000	5.7
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,031,000	6.5
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	2,961,000	18.7
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	257,000	1.6
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	269,000	1.7
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	783,000	5.0
Construction facilities	753,000	4.8
Subtotal direct investment	15,815,000	100.0
Engineering design and supervision	1,740,000	11.0
Construction field expense	1,740,000	11.0
Contractor fees	791,000	5.0
Contingency	1,582,000	10.0
Subtotal fixed investment	21,668,000	137.0
Allowance for startup and modifications	2,167,000	13.7
Interest during construction (8%/annum rate)	1,733,000	11.0
Total capital investment	25,568,000	161.7

[a] Basis:
Stack gas reheat to 175°F by indirect steam reheat.
Midwest plant location represents projects beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-128. Magnesia Slurry—Regeneration Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; 98,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	134 tons	26.00/ton	3,500	0.04
Magnesium oxide (98%)	1,086 tons	155.00/ton	168,300	1.91
Coke	678 tons	15.00/ton	10,200	0.12
Catalyst	1,600 liters	1.65/liter	2,600	0.03
Subtotal raw material			184,600	2.10
Conversion costs				
Operating labor and supervision	39,200 man-hr	8.00/man-hr	313,600	3.57
Utilities				
Fuel oil (No. 6)	4,761,000 gal	0.23/gal	1,095,000	12.46
Steam	440,000 M lb	0.70/M lb	308,000	3.50
Heat credit	18,000 MM Btu	0.60/MM Btu	(10,800)	(0.12)
Process water	1,985,400 M gal	0.04/M gal	79,400	0.90
Electricity	66,640,000 kWh	0.010/kWh	666,400	7.58
Maintenance				
Labor and material, .07 × 15,815,000			1,107,100	12.60
Analyses			102,000	1.16
Subtotal conversion costs			3,660,700	41.65
Subtotal direct costs			3,845,300	43.75
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,809,600	43.34
Overhead				
Plant, 20% of conversion costs			732,100	8.33
Administrative and marketing, 11% of conversion costs			402,700	4.58
Subtotal indirect costs			4,944,400	56.25
Total annual operating cost			8,789,700	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	89.51	6.70	2.51	27.90	274.16

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $25,568,000; subtotal direct investment, $15,815,000.
Working capital, $681,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-129

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 80% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 25568000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	32100	98200	8.00	11449500	785600	10663900	10663900
2	7000	31500000	1312500	32100	98200	8.00	11272300	785600	10486700	21150600
3	7000	31500000	1312500	32100	98200	8.00	11095000	785600	10309400	31460000
4	7000	31500000	1312500	32100	98200	8.00	10917700	785600	10132100	41592100
5	7000	31500000	1312500	32100	98200	8.00	10740400	785600	9954800	51546900
6	7000	31500000	1312500	32100	98200	8.00	10563200	785600	9777600	61324500
7	7000	31500000	1312500	32100	98200	8.00	10385900	785600	9600300	70924800
8	7000	31500000	1312500	32100	98200	8.00	10208600	785600	9423000	80347800
9	7000	31500000	1312500	32100	98200	8.00	10031300	785600	9245700	89593500
10	7000	31500000	1312500	32100	98200	8.00	9854000	785600	9068400	98661900
11	5000	22500000	937500	22900	70100	8.00	8457200	560800	7896400	106558300
12	5000	22500000	937500	22900	70100	8.00	8279900	560800	7719100	114277400
13	5000	22500000	937500	22900	70100	8.00	8102600	560800	7541800	121819200
14	5000	22500000	937500	22900	70100	8.00	7925300	560800	7364500	129183700
15	5000	22500000	937500	22900	70100	8.00	7748000	560800	7187200	136370900
16	3500	15750000	656200	16000	49100	8.00	6617100	392800	6224300	142595200
17	3500	15750000	656200	16000	49100	8.00	6439800	392800	6047000	148642200
18	3500	15750000	656200	16000	49100	8.00	6262500	392800	5869700	154511900
19	3500	15750000	656200	16000	49100	8.00	6085200	392800	5692400	160204300
20	3500	15750000	656200	16000	49100	8.00	5908000	392800	5515200	165719500
21	1500	6750000	281200	6900	21000	8.00	4358100	168000	4190100	169909600
22	1500	6750000	281200	6900	21000	8.00	4180800	168000	4012800	173922400
23	1500	6750000	281200	6900	21000	8.00	4003500	168000	3835500	177757900
24	1500	6750000	281200	6900	21000	8.00	3826200	168000	3658200	181416100
25	1500	6750000	281200	6900	21000	8.00	3649000	168000	3481000	184897100
26	1500	6750000	281200	6900	21000	8.00	3471700	168000	3303700	188200800
27	1500	6750000	281200	6900	21000	8.00	3294400	168000	3126400	191327200
28	1500	6750000	281200	6900	21000	8.00	3117100	168000	2949100	194276300
29	1500	6750000	281200	6900	21000	8.00	2939800	168000	2771800	197048100
30	1500	6750000	281200	6900	21000	8.00	2762600	168000	2594600	199642700
TOT	127500	573750000	23905500	584500	1788000		213946700	14304000	199642700	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	8.95	0.60	8.35
MILLS PER KILOWATT-HOUR	3.36	0.23	3.13
CENTS PER MILLION BTU HEAT INPUT	37.29	2.49	34.80
DOLLARS PER TON OF SULFUR REMOVED	366.03	24.47	341.56
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	87276500	6156700	81119800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	8.48	0.59	7.89
MILLS PER KILOWATT-HOUR	3.18	0.22	2.96
CENTS PER MILLION BTU HEAT INPUT	35.35	2.49	32.86
DOLLARS PER TON OF SULFUR REMOVED	347.02	24.48	322.54

Table B-130. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 15.8 tons/hr 100% H_2SO_4; particulate scrubber required for fly ash removal)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	210,000	1.1
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	270,000	1.4
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, fly ash neutralization facilities and all ductwork between outlet of supplemental fan and particulate scrubber)	4,716,000	24.7
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts between SO_2 scrubber and stack gas plenum)	3,172,000	16.6
Stack gas reheat (4 direct oil-fired reheaters)	305,000	1.6
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	1,185,000	6.2
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	789,000	4.1
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	1,065,000	5.6
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,211,000	6.4
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	3,608,000	18.9
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	329,000	1.7
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	454,000	2.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	867,000	4.5
Construction facilities	909,000	4.8
Subtotal direct investment	19,090,000	100.0
Engineering design and supervision	2,291,000	12.0
Construction field expense	2,482,000	13.0
Contractor fees	1,336,000	7.0
Contingency	2,100,000	11.0
Subtotal fixed investment	27,299,000	143.0
Allowance for startup and modifications	2,730,000	14.3
Interest during construction (8%/annum rate)	2,184,000	11.4
Total capital investment	32,213,000	168.7

[a] Basis:

Stack gas reheat to 175°F by indirect steam reheat.

Midwest plant location represents projects beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Remaining life of power unit, 25 yr.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-131. Magnesia Slurry–Regeneration Process Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 112,900 tons/yr 100% H_2SO_4; particulate scrubber required for fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Lime (1st stage neutralization)	137 tons	26.00/ton	3,600	0.03
Magnesium oxide (98%)	1,110 tons	155.00/ton	172,100	1.54
Coke	780 tons	15.00/ton	11,700	0.10
Catalyst	1,840 liters	1.65/liter	3,000	0.03
Subtotal raw material			190,400	1.70
Conversion costs				
Operating labor and supervision	39,200 man-hr	8.00/man-hr	313,600	2.79
Utilities				
Fuel oil (No. 6)	9,160,000 gal	0.23/gal	2,106,800	18.77
Heat credit	20,800 MM Btu	-0.60/MM Btu	(12,500)	(0.11)
Process water	2,256,100 M gal	0.04/M gal	90,200	0.80
Electricity	72,640,000 kWh	0.010/kWh	726,400	6.47
Maintenance				
Labor and material, .07 x 19,090,000			1,336,300	11.90
Analyses			102,000	0.91
Subtotal conversion costs			4,662,800	41.53
Subtotal direct costs			4,853,200	43.23
Indirect Costs				
Average capital charges at 15.3% of total capital investment			4,928,600	43.89
Overhead				
Plant, 20% of conversion costs			932,600	8.31
Administrative and marketing, 11% of conversion costs			512,900	4.57
Subtotal indirect costs			6,374,100	56.77
Total annual operating cost			11,227,300	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	99.44	8.37	3.21	34.87	304.59

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $32,213,000; subtotal direct investment, $19,090,000.
Working capital, $858,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-132

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW EXIST. COAL FIRED POWER UNIT, 3.5% S, 90% SO2 REMOVAL, FLYASH REMOVED BY PART. SCRUB.

FIXED INVESTMENT: $ 32213000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36900	112900	8.00	14577400	903200	13674200	13674200
7	7000	32200000	1341700	36900	112900	8.00	14309400	903200	13406200	27080400
8	7000	32200000	1341700	36900	112900	8.00	14041400	903200	13138200	40218600
9	7000	32200000	1341700	36900	112900	8.00	13773400	903200	12870200	53088800
10	7000	32200000	1341700	36900	112900	8.00	13505400	903200	12602200	65691000
11	5000	23000000	958300	26300	80600	8.00	11671900	644800	11027100	76718100
12	5000	23000000	958300	26300	80600	8.00	11403900	644800	10759100	87477200
13	5000	23000000	958300	26300	80600	8.00	11135800	644800	10491000	97968200
14	5000	23000000	958300	26300	80600	8.00	10867800	644800	10223000	108191200
15	5000	23000000	958300	26300	80600	8.00	10599800	644800	9955000	118146200
16	3500	16100000	670800	18400	56500	8.00	9112700	452000	8660700	126806900
17	3500	16100000	670800	18400	56500	8.00	8844700	452000	8392700	135199600
18	3500	16100000	670800	18400	56500	8.00	8576700	452000	8124700	143324300
19	3500	16100000	670800	18400	56500	8.00	8308700	452000	7856700	151181000
20	3500	16100000	670800	18400	56500	8.00	8040700	452000	7588700	158769700
21	1500	6900000	287500	7900	24200	8.00	6030200	193600	5836600	164606300
22	1500	6900000	287500	7900	24200	8.00	5762200	193600	5568600	170174900
23	1500	6900000	287500	7900	24200	8.00	5494200	193600	5300600	175475500
24	1500	6900000	287500	7900	24200	8.00	5226200	193600	5032600	180508100
25	1500	6900000	287500	7900	24200	8.00	4958200	193600	4764600	185272700
26	1500	6900000	287500	7900	24200	8.00	4690100	193600	4496500	189769200
27	1500	6900000	287500	7900	24200	8.00	4422100	193600	4228500	193997700
28	1500	6900000	287500	7900	24200	8.00	4154100	193600	3960500	197958200
29	1500	6900000	287500	7900	24200	8.00	3886100	193600	3692500	201650700
30	1500	6900000	287500	7900	24200	8.00	3618100	193600	3424500	205075200
TOT	92500	425500000	17729000	487000	1492000		217011200	11936000	205075200	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	12.24	0.67	11.57
MILLS PER KILOWATT-HOUR	4.69	0.26	4.43
CENTS PER MILLION BTU HEAT INPUT	51.00	2.80	48.20
DOLLARS PER TON OF SULFUR REMOVED	445.61	24.51	421.10
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	99762800	5887000	93875800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	11.41	0.68	10.73
MILLS PER KILOWATT-HOUR	4.37	0.25	4.12
CENTS PER MILLION BTU HEAT INPUT	47.53	2.80	44.73
DOLLARS PER TON OF SULFUR REMOVED	415.16	24.50	390.66

Table B-133. Magnesia Slurry—Regeneration Process Summary of Estimated Fixed Investment[a]

(200-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 3.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	69,000	1.3
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	90,000	1.7
Sulfur dioxide scrubbers and ducts (2 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fan)	1,440,000	27.6
Stack gas reheat (2 direct oil-fired reheaters)	103,000	2.0
Fans (2 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	208,000	4.0
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	249,000	4.8
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	373,000	7.2
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	438,000	8.4
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	1,189,000	22.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	99,000	1.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	186,000	3.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	522,000	10.0
Construction facilities	248,000	4.7
Subtotal direct investment	5,214,000	100.0
Engineering design and supervision	678,000	13.0
Construction field expense	678,000	13.0
Contractor fees	365,000	7.0
Contingency	574,000	11.0
Subtotal fixed investment	7,509,000	144.0
Allowance for startup and modifications	751,000	14.4
Interest during construction (8%/annum rate)	601,000	11.5
Total capital investment	8,861,000	169.9

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-134. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 24,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	239 tons	155.00/ton	37,000	1.15
Coke	166 tons	15.00/ton	2,500	0.08
Catalyst	393 liters	1.65/liter	600	0.02
Subtotal raw material			40,100	1.25
Conversion costs				
Operating labor and supervision	28,360 man-hr	8.00/man-hr	226,900	7.08
Utilities				
Fuel oil (No. 6)	1,988,000 gal	0.23/gal	457,200	14.27
Heat credit	4,400 MM Btu	-1.60/MM Btu	(7,000)	(0.22)
Process water	508,000 M gal	0.08/M gal	40,600	1.27
Electricity	12,470,000 kWh	0.019/kWh	236,900	7.39
Maintenance				
Labor and material, .08 x 5,214,000			417,100	13.02
Analyses			36,000	1.12
Subtotal conversion costs			1,407,700	43.93
Subtotal direct costs			1,447,800	45.18
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,320,300	41.20
Overhead				
Plant, 20% of conversion costs			281,500	8.79
Administrative and marketing, 11% of conversion costs			154,800	4.83
Subtotal indirect costs			1,756,600	54.82
Total annual operating cost			3,204,400	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	132.96	1.56	2.29	24.88	407.17

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 2,058,200 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $8,861,000; subtotal direct investment, $5,214,000.
Working capital, $255,900.

Table B-135

MAGNESIA SLURRY-REGENERATION PROCESS, 200 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 8861000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	2058200	7900	24100	8.00	4126300	192800	3933500	3933500
2	7000	12880000	2058200	7900	24100	8.00	4064800	192800	3872000	7805500
3	7000	12880000	2058200	7900	24100	8.00	4003400	192800	3810600	11616100
4	7000	12880000	2058200	7900	24100	8.00	3942000	192800	3749200	15365300
5	7000	12880000	2058200	7900	24100	8.00	3880500	192800	3687700	19053000
6	7000	12880000	2058200	7900	24100	8.00	3819100	192800	3626300	22679300
7	7000	12880000	2058200	7900	24100	8.00	3757600	192800	3564800	26244100
8	7000	12880000	2058200	7900	24100	8.00	3696200	192800	3503400	29747500
9	7000	12880000	2058200	7900	24100	8.00	3634700	192800	3441900	33189400
10	7000	12880000	2058200	7900	24100	8.00	3573300	192800	3380500	36569900
11	5000	9200000	1470100	5600	17200	8.00	3068900	137600	2931300	39501200
12	5000	9200000	1470100	5600	17200	8.00	3007400	137600	2869800	42371000
13	5000	9200000	1470100	5600	17200	8.00	2946000	137600	2808400	45179400
14	5000	9200000	1470100	5600	17200	8.00	2884500	137600	2746900	47926300
15	5000	9200000	1470100	5600	17200	8.00	2823100	137600	2685500	50611800
16	3500	6440000	1029100	3900	12100	8.00	2411400	96800	2314600	52926400
17	3500	6440000	1029100	3900	12100	8.00	2350000	96800	2253200	55179600
18	3500	6440000	1029100	3900	12100	8.00	2288600	96800	2191800	57371400
19	3500	6440000	1029100	3900	12100	8.00	2227100	96800	2130300	59501700
20	3500	6440000	1029100	3900	12100	8.00	2165700	96800	2068900	61570600
21	1500	2760000	441000	1700	5200	8.00	1590600	41600	1549000	63119600
22	1500	2760000	441000	1700	5200	8.00	1529200	41600	1487600	64607200
23	1500	2760000	441000	1700	5200	8.00	1467700	41600	1426100	66033300
24	1500	2760000	441000	1700	5200	8.00	1406300	41600	1364700	67398000
25	1500	2760000	441000	1700	5200	8.00	1344900	41600	1303300	68701300
26	1500	2760000	441000	1700	5200	8.00	1283400	41600	1241800	69943100
27	1500	2760000	441000	1700	5200	8.00	1222000	41600	1180400	71123500
28	1500	2760000	441000	1700	5200	8.00	1160500	41600	1118900	72242400
29	1500	2760000	441000	1700	5200	8.00	1099100	41600	1057500	73299900
30	1500	2760000	441000	1700	5200	8.00	1037600	41600	996000	74295900
TOT	127500	234600000	37488000	143500	439500		77811900	3516000	74295900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	2.08	0.10	1.98
MILLS PER KILOWATT-HOUR	3.05	0.14	2.91
CENTS PER MILLION BTU HEAT INPUT	33.17	1.50	31.67
DOLLARS PER TON OF SULFUR REMOVED	542.24	24.50	517.74
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	31601500	1511600	30089900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.96	0.09	1.87
MILLS PER KILOWATT-HOUR	2.88	0.14	2.74
CENTS PER MILLION BTU HEAT INPUT	31.30	1.49	29.81
DOLLARS PER TON OF SULFUR REMOVED	511.35	24.46	486.89

Table B-136. Magnesia Slurry–Regeneration Process Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; 3.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	68,000	0.9
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	88,000	1.1
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fan)	3,260,000	41.5
Stack gas reheat (4 direct oil-fired reheaters)	245,000	3.1
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	471,000	6.0
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	245,000	3.1
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	368,000	4.7
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	432,000	5.5
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	1,170,000	14.9
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	97,000	1.3
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	301,000	3.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	733,000	9.3
Construction facilities	374,000	4.8
Subtotal direct investment	7,852,000	100.0
Engineering design and supervision	864,000	11.0
Construction field expense	864,000	11.0
Contractor fees	393,000	5.0
Contingency	785,000	10.0
Subtotal fixed investment	10,758,000	137.0
Allowance for startup and modifications	1,076,000	13.7
Interest during construction (8%/annum rate)	861,000	11.0
Total capital investment	12,695,000	161.7

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-137. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; 23,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	232 tons	155.00/ton	36,000	0.77
Coke	163 tons	15.00/ton	2,400	0.05
Catalyst	394 liters	1.65/liter	700	0.02
Subtotal raw material			39,100	0.84
Conversion costs				
Operating labor and supervision	30,440 man-hr	8.00/man-hr	243,500	5.26
Utilities				
Fuel oil (No. 6)	3,147,000 gal	0.23/gal	723,800	15.63
Heat credit	4,300 MM Btu	-1.60/MM Btu	(6,900)	(0.15)
Process water	601,800 M gal	0.07/M gal	42,100	0.91
Electricity	24,710,000 kWh	0.018/kWh	444,800	9.60
Maintenance				
Labor and material, .07 x 7,852,000			549,600	11.86
Analyses			66,000	1.42
Subtotal conversion costs			2,062,900	44.53
Subtotal direct costs			2,102,000	45.37
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,891,600	40.82
Overhead				
Plant, 20% of conversion costs			412,600	8.91
Administrative and marketing, 11% of conversion costs			226,900	4.90
Subtotal indirect costs			2,531,100	54.63
Total annual operating cost			4,633,100	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	196.32	0.92	1.32	14.71	602.48

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $12,695,000; subtotal direct investment, $7,852,000.
Working capital, $371,300.

Table B-138

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 1.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 12695000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	7700	23600	8.00	5953800	188800	5765000	5765000
2	7000	31500000	5033600	7700	23600	8.00	5865700	188800	5676900	11441900
3	7000	31500000	5033600	7700	23600	8.00	5777700	188800	5588900	17030800
4	7000	31500000	5033600	7700	23600	8.00	5689700	188800	5500900	22531700
5	7000	31500000	5033600	7700	23600	8.00	5601700	188800	5412900	27944600
6	7000	31500000	5033600	7700	23600	8.00	5513600	188800	5324800	33269400
7	7000	31500000	5033600	7700	23600	8.00	5425600	188800	5236800	38506200
8	7000	31500000	5033600	7700	23600	8.00	5337600	188800	5148800	43655000
9	7000	31500000	5033600	7700	23600	8.00	5249600	188800	5060800	48715800
10	7000	31500000	5033600	7700	23600	8.00	5161500	188800	4972700	53688500
11	5000	22500000	3595400	5500	16900	8.00	4406100	135200	4270900	57959400
12	5000	22500000	3595400	5500	16900	8.00	4318100	135200	4182900	62142300
13	5000	22500000	3595400	5500	16900	8.00	4230100	135200	4094900	66237200
14	5000	22500000	3595400	5500	16900	8.00	4142000	135200	4006800	70244000
15	5000	22500000	3595400	5500	16900	8.00	4054000	135200	3918800	74162800
16	3500	15750000	2516800	3800	11800	8.00	3443900	94400	3349500	77512300
17	3500	15750000	2516800	3800	11800	8.00	3355900	94400	3261500	80773800
18	3500	15750000	2516800	3800	11800	8.00	3267800	94400	3173400	83947200
19	3500	15750000	2516800	3800	11800	8.00	3179800	94400	3085400	87032600
20	3500	15750000	2516800	3800	11800	8.00	3091800	94400	2997400	90030000
21	1500	6750000	1078600	1600	5100	8.00	2249700	40800	2208900	92238900
22	1500	6750000	1078600	1600	5100	8.00	2161700	40800	2120900	94359800
23	1500	6750000	1078600	1600	5100	8.00	2073700	40800	2032900	96392700
24	1500	6750000	1078600	1600	5100	8.00	1985700	40800	1944900	98337600
25	1500	6750000	1078600	1600	5100	8.00	1897600	40800	1856800	100194400
26	1500	6750000	1078600	1600	5100	8.00	1809600	40800	1768800	101963200
27	1500	6750000	1078600	1600	5100	8.00	1721600	40800	1680800	103644000
28	1500	6750000	1078600	1600	5100	8.00	1633600	40800	1592800	105236800
29	1500	6750000	1078600	1600	5100	8.00	1545500	40800	1504700	106741500
30	1500	6750000	1078600	1600	5100	8.00	1457500	40800	1416700	108158200
TOT	127500	573750000	91683000	139500	430500		111602200	3444000	108158200	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.22	0.04	1.18	
MILLS PER KILOWATT-HOUR							1.75	0.05	1.70	
CENTS PER MILLION BTU HEAT INPUT							19.45	0.60	18.85	
DOLLARS PER TON OF SULFUR REMOVED							800.02	24.69	775.33	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							45510900	1480600	44030300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.15	0.03	1.12	
MILLS PER KILOWATT-HOUR							1.66	0.05	1.61	
CENTS PER MILLION BTU HEAT INPUT							18.43	0.60	17.83	
DOLLARS PER TON OF SULFUR REMOVED							756.00	24.60	731.40	

Table B-139. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 8.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	126,000	1.3
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	159,000	1.6
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fan)	3,260,000	32.8
Stack gas reheat (4 direct oil-fired reheaters)	245,000	2.4
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	471,000	4.7
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	461,000	4.6
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	655,000	6.6
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	755,000	7.6
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	2,126,000	21.4
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	181,000	1.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	301,000	3.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	733,000	7.4
Construction facilities	474,000	4.8
Subtotal direct investment	9,947,000	100.0
Engineering design and supervision	1,094,000	11.0
Construction field expense	1,094,000	11.0
Contractor fees	497,000	5.0
Contingency	995,000	10.0
Subtotal fixed investment	13,627,000	137.0
Allowance for startup and modifications	1,363,000	13.7
Interest during construction (8%/annum rate)	1,090,000	11.0
Total capital investment	16,080,000	161.7

[a] Basis:

Stack gas reheat to 175° F by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-140. Magnesia Slurry–Regeneration Process Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 58,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	579 tons	155.00/ton	89,700	1.47
Coke	407 tons	15.00/ton	6,100	0.10
Catalyst	960 liters	1.65/liter	1,600	0.03
Subtotal raw material			97,400	1.60
Conversion costs				
Operating labor and supervision	32,520 man-hr	8.00/man-hr	260,200	4.27
Utilities				
Fuel oil (No. 6)	4,861,000 gal	0.23/gal	1,118,000	18.35
Heat credit	10,800 MM Btu	1.60/MM Btu	(17,300)	(0.28)
Process water	1,241,100 M gal	0.05/M gal	62,100	1.02
Electricity	30,510,000 kWh	0.018/kWh	549,200	9.01
Maintenance				
Labor and material, .07 x 9,947,000			696,300	11.43
Analyses			79,200	1.30
Subtotal conversion costs			2,747,700	45.10
Subtotal direct costs			2,845,100	46.70
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,395,900	39.32
Overhead				
Plant, 20% of conversion costs			549,500	9.02
Administrative and marketing, 11% of conversion costs			302,200	4.96
Subtotal indirect costs			3,247,600	53.30
Total annual operating cost			6,092,700	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	103.44	1.21	1.74	19.34	316.83

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $16,080,000; subtotal direct investment, $9,947,000.
Working capital, $503,300.

Table B-141

MAGNESIA SLURRY-REGENERATION PROCESS, 50C MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 16080000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	19200	58900	8.00	7765500	471200	7294300	7294300
2	7C00	31500000	5033600	19200	58900	8.00	7654100	471200	7182900	14477200
3	7000	31500000	5033600	19200	58900	8.00	7542600	471200	7071400	21548600
4	7000	31500000	5033600	19200	58900	8.00	7431100	471200	6959900	28508500
5	7000	31500000	5033600	19200	58900	8.00	7319600	471200	6848400	35356900
6	7000	31500000	5033600	19200	58900	8.00	7208100	471200	6736900	42093800
7	7000	31500000	5033600	19200	58900	8.00	7096600	471200	6625400	48719200
8	7000	31500000	5033600	19200	58900	8.00	6985100	471200	6513900	55233100
9	7000	31500000	5033600	19200	58900	8.00	6873600	471200	6402400	61635500
10	7000	31500000	5033600	19200	58900	8.00	6762100	471200	6290900	67926400
11	5000	22500000	3595400	13700	42100	8.00	5733100	336800	5396300	73322700
12	5000	22500000	3595400	13700	42100	8.00	5621600	336800	5284800	78607500
13	5000	22500000	3595400	13700	42100	8.00	5510100	336800	5173300	83780800
14	5000	22500000	3595400	13700	42100	8.00	5398600	336800	5061800	88842600
15	5000	22500000	3595400	13700	42100	8.00	5287100	336800	4950300	93792900
16	3500	15750000	2516800	9600	29400	8.00	4461300	235200	4226100	98019000
17	3500	15750000	2516800	9600	29400	8.00	4349800	235200	4114600	102133600
18	3500	15750000	2516800	9600	29400	8.00	4238300	235200	4003100	106136700
19	3500	15750000	2516800	9600	29400	8.00	4126900	235200	3891700	110028400
20	3500	15750000	2516800	9600	29400	8.00	4015400	235200	3780200	113808600
21	1500	6750000	1078600	4100	12600	8.00	2882400	100800	2781600	116590200
22	1500	6750000	1078600	4100	12600	8.00	2770900	100800	2670100	119260300
23	1500	6750000	1078600	4100	12600	8.00	2659400	100800	2558600	121818900
24	1500	6750000	1078600	4100	12600	8.00	2547900	100800	2447100	124266000
25	1500	6750000	1078600	4100	12600	8.00	2436400	100800	2335600	126601600
26	1500	6750000	1078600	4100	12600	8.00	2324900	100800	2224100	128825700
27	1500	6750000	1078600	4100	12600	8.00	2213500	100800	2112700	130938400
28	1500	6750000	1078600	4100	12600	8.00	2102000	100800	2001200	132939600
29	1500	6750000	1078600	4100	12600	8.00	1990500	100800	1889700	134829300
30	1500	6750000	1078600	4100	12600	8.00	1879000	100800	1778200	136607500
TOT	127500	573750000	91683000	349500	1072500		145187500	8580000	136607500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.58	0.09	1.49
MILLS PER KILOWATT-HOUR	2.28	0.14	2.14
CENTS PER MILLION BTU HEAT INPUT	25.31	1.50	23.81
DOLLARS PER TON OF SULFUR REMOVED	415.41	24.54	390.87
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	59366500	3693100	55673400
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.50	0.09	1.41
MILLS PER KILOWATT-HOUR	2.16	0.13	2.03
CENTS PER MILLION BTU HEAT INPUT	24.05	1.50	22.55
DOLLARS PER TON OF SULFUR REMOVED	394.72	24.55	370.17

Table B-142. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; 13.5 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	173,000	1.5
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	215,000	1.8
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fan)	3,260,000	28.1
Stack gas reheat (4 direct oil-fired reheaters)	245,000	2.1
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	471,000	4.1
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	638,000	5.5
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	880,000	7.6
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,007,000	8.7
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	2,883,000	24.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	249,000	2.1
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	301,000	2.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	733,000	6.3
Construction facilities	553,000	4.8
Subtotal direct investment	11,608,000	100.0
Engineering design and supervision	1,277,000	11.0
Construction field expense	1,277,000	11.0
Contractor fees	580,000	5.0
Contingency	1,161,000	10.0
Subtotal fixed investment	15,903,000	137.0
Allowance for startup and modifications	1,590,000	13.7
Interest during construction (8%/annum rate)	1,272,000	11.0
Total capital investment	18,765,000	161.7

[a] Basis:
Stack gas reheat to 175°F by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-143. Magnesia Slurry – Regeneration Process
Total Average Annual Operating Costs – Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 4.0% S in fuel, 90% SO_2 removal; 94,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	926 tons	155.00/ton	143,500	1.95
Coke	651 tons	15.00/ton	9,800	0.13
Catalyst	1,536 liters	1.65/liter	2,500	0.03
Subtotal raw material			155,800	2.11
Conversion costs				
Operating labor and supervision	34,600 man hr	8.00/man-hr	276,800	3.74
Utilities				
Fuel oil (No. 6)	6,575,000 gal	0.23/gal	1,512,300	20.46
Heat credit	17,300 MM Btu	-1.60/MM Btu	(27,700)	(0.37)
Process water	1,880,400 M gal	0.04/M gal	75,200	1.02
Electricity	36,320,000 kWh	0.018/kWh	653,800	8.84
Maintenance				
Labor and material, .07 × 11,608,000			812,600	10.99
Analyses			87,600	1.18
Subtotal conversion costs			3,390,600	45.86
Subtotal direct costs			3,546,400	47.97
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,796,000	37.81
Overhead				
Plant, 20% of conversion costs			678,100	9.17
Administrative and marketing, 11% of conversion costs			373,000	5.05
Subtotal indirect costs			3,847,100	52.03
Total annual operating cost			7,393,500	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	78.49	1.47	2.11	23.47	240.28

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $18,765,000; subtotal direct investment, $11,608,000.
Working capital, $627,900.

Table B-144

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 4.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 18765000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	30800	94200	8.00	9345700	753600	8592100	8592100
2	7000	31500000	5033600	30800	94200	8.00	9215600	753600	8462000	17054100
3	7000	31500000	5033600	30800	94200	8.00	9085500	753600	8331900	25386000
4	7000	31500000	5033600	30800	94200	8.00	8955400	753600	8201800	33587800
5	7000	31500000	5033600	30800	94200	8.00	8825300	753600	8071700	41659500
6	7000	31500000	5033600	30800	94200	8.00	8695200	753600	7941600	49601100
7	7000	31500000	5033600	30800	94200	8.00	8565100	753600	7811500	57412600
8	7000	31500000	5033600	30800	94200	8.00	8435000	753600	7681400	65094000
9	7000	31500000	5033600	30800	94200	8.00	8304900	753600	7551300	72645300
10	7000	31500000	5033600	30800	94200	8.00	8174800	753600	7621200	80266500
11	5000	22500000	3595400	22000	67300	8.00	6888000	538400	6349600	86416100
12	5000	22500000	3595400	22000	67300	8.00	6757900	538400	6219500	92635600
13	5000	22500000	3595400	22000	67300	8.00	6627800	538400	6089400	98725000
14	5000	22500000	3595400	22000	67300	8.00	6497700	538400	5959300	104684300
15	5000	22500000	3595400	22000	67300	8.00	6367600	538400	5829200	110513500
16	3500	15750000	2516800	15400	47100	8.00	5340700	376800	4963900	115477400
17	3500	15750000	2516800	15400	47100	8.00	5210600	376800	4833800	120311200
18	3500	15750000	2516800	15400	47100	8.00	5080500	376800	4703700	125014900
19	3500	15750000	2516800	15400	47100	8.00	4950300	376800	4573500	129588400
20	3500	15750000	2516800	15400	47100	8.00	4820200	376800	4443400	134031800
21	1500	6750000	1078600	6600	20200	8.00	3415700	161600	3254100	137285900
22	1500	6750000	1078600	6600	20200	8.00	3285600	161600	3124000	140409900
23	1500	6750000	1078600	6600	20200	8.00	3155500	161600	2993900	143403800
24	1500	6750000	1078600	6600	20200	8.00	3025400	161600	2863800	146267600
25	1500	6750000	1078600	6600	20200	8.00	2895300	161600	2733700	149001300
26	1500	6750000	1078600	6600	20200	8.00	2765200	161600	2603600	151604900
27	1500	6750000	1078600	6600	20200	8.00	2635100	161600	2473500	154078400
28	1500	6750000	1078600	6600	20200	8.00	2505000	161600	2343400	156421800
29	1500	6750000	1078600	6600	20200	8.00	2374900	161600	2213300	158635100
30	1500	6750000	1078600	6600	20200	8.00	2266800	161600	2083200	160718300
TOT	127500	573750000	91683000	561000	1716000		174446300	13728000	160718300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.90	0.15	1.75	
MILLS PER KILOWATT-HOUR							2.74	0.22	2.52	
CENTS PER MILLION BTU HEAT INPUT							30.40	2.39	28.01	
DOLLARS PER TON OF SULFUR REMOVED							310.96	24.47	286.49	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							71479700	5906900	65572800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.81	0.15	1.66	
MILLS PER KILOWATT-HOUR							2.61	0.22	2.39	
CENTS PER MILLION BTU HEAT INPUT							28.95	2.39	26.56	
DOLLARS PER TON OF SULFUR REMOVED							296.10	24.46	271.64	

Table B-145. Magnesia Slurry–Regeneration Process Summary of Estimated Fixed Investment[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 8.6 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	138,000	1.1
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	180,000	1.5
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between outlet of supplemental fan and stack gas plenum)	4,015,000	33.2
Stack gas reheat (4 direct oil-fired reheaters)	263,000	2.2
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fan)	999,000	8.3
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	511,000	4.2
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	716,000	5.9
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	826,000	6.8
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	2,398,000	19.9
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	214,000	1.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	429,000	3.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	812,000	6.7
Construction facilities	575,000	4.8
Subtotal direct investment	12,076,000	100.0
Engineering design and supervision	1,449,000	12.0
Construction field expense	1,570,000	13.0
Contractor fees	845,000	7.0
Contingency	1,328,000	11.0
Subtotal fixed investment	17,268,000	143.0
Allowance for startup and modifications	1,727,000	14.3
Interest during construction (8%/annum rate)	1,381,000	11.4
Total capital investment	20,376,000	168.7

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Remaining life of power unit, 25 yr.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-146. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 60,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	592 tons	155.00/ton	91,800	1.26
Coke	416 tons	15.00/ton	6,200	0.08
Catalyst	981 liters	1.65/liter	1,600	0.02
Subtotal raw material			99,600	1.36
Conversion costs				
Operating labor and supervision	32,520 man-hr	8.00/man-hr	260,200	3.56
Utilities				
Fuel oil (No. 6)	5,557,000 gal	0.23/gal	1,278,100	17.48
Heat credit	11,100 MM Btu	-1.60/MM Btu	(17,800)	(0.24)
Process water	1,268,800 M gal	0.05/M gal	63,400	0.87
Electricity	34,030,000 kWh	0.018/kWh	612,500	8.38
Maintenance				
Labor and material, .07 x 12,076,000			845,300	11.57
Analyses			81,600	1.12
Subtotal conversion costs			3,123,300	42.74
Subtotal direct costs			3,222,900	44.10
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,117,500	42.65
Overhead				
Plant, 20% of conversion costs			624,700	8.55
Administrative and marketing, 11% of conversion costs			343,600	4.70
Subtotal indirect costs			4,085,800	55.90
Total annual operating cost			7,308,700	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	121.41	1.42	2.09	22.70	371.75

[a] Basis:
Remaining life of power plant, 25 yr.
Oil burned, 5,145,400 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $20,376,000; subtotal direct investment, $12,076,000.
Working capital, $569,900.

Table B-147

MAGNESIA SLURRY-REGENERATION PROCESS, 500 MW EXISTING OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 20376000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5145400	19700	60200	8.00	9427800	481600	8946200	8946200
7	7000	32200000	5145400	19700	60200	8.00	9258300	481600	8776700	17722900
8	7000	32200000	5145400	19700	60200	8.00	9088800	481600	8607200	26330100
9	7000	32200000	5145400	19700	60200	8.00	8919200	481600	8437600	34767700
10	7000	32200000	5145400	19700	60200	8.00	8769700	481600	8268100	43035800
11	5000	23000000	3675300	14000	43000	8.00	7541300	344000	7197300	50233100
12	5000	23000000	3675300	14000	43000	8.00	7371800	344000	7027800	57260900
13	5000	23000000	3675300	14000	43000	8.00	7202300	344000	6858300	64119200
14	5000	23000000	3675300	14000	43000	8.00	7032700	344000	6688700	70807900
15	5000	23000000	3675300	14000	43000	8.00	6863200	344000	6519200	77327100
16	3500	16100000	2572700	9800	30100	8.00	5884600	240800	5643800	82970900
17	3500	16100000	2572700	9800	30100	8.00	5715100	240800	5474300	88445200
18	3500	16100000	2572700	9800	30100	8.00	5545600	240800	5304800	93750000
19	3500	16100000	2572700	9800	30100	8.00	5376000	240800	5135200	98885200
20	3500	16100000	2572700	9800	30100	8.00	5206500	240800	4965700	103850900
21	1500	6900000	1102600	4200	12900	8.00	3878800	103200	3775600	107626500
22	1500	6900000	1102600	4200	12900	8.00	3709300	103200	3606100	111232600
23	1500	6900000	1102600	4200	12900	8.00	3539800	103200	3436600	114669200
24	1500	6900000	1102600	4200	12900	8.00	3370200	103200	3267000	117936200
25	1500	6900000	1102600	4200	12900	8.00	3200700	103200	3097500	121033700
26	1500	6900000	1102600	4200	12900	8.00	3031200	103200	2928000	123961700
27	1500	6900000	1102600	4200	12900	8.00	2861700	103200	2758500	126720200
28	1500	6900000	1102600	4200	12900	8.00	2692200	103200	2589000	129309200
29	1500	6900000	1102600	4200	12900	8.00	2522600	103200	2419400	131728600
30	1500	6900000	1102600	4200	12900	8.00	2353100	103200	2269900	133978500
TOT	92500	425500000	67993000	259500	795500		140342500	6364000	133978500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							2.06	0.09	1.97	
MILLS PER KILOWATT-HOUR							3.03	0.13	2.90	
CENTS PER MILLION BTU HEAT INPUT							32.98	1.49	31.49	
DOLLARS PER TON OF SULFUR REMOVED							540.82	24.53	516.29	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							64532400	3139100	61393300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.92	0.09	1.83	
MILLS PER KILOWATT-HOUR							2.83	0.14	2.69	
CENTS PER MILLION BTU HEAT INPUT							30.75	1.50	29.25	
DOLLARS PER TON OF SULFUR REMOVED							503.77	24.51	479.26	

Table B-148. Magnesia Slurry–Regeneration Process
Summary of Estimated Fixed Investment[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 16.3 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Magnesium oxide and coke receiving and storage (pneumatic conveyor and blower, hoppers, conveyors, elevators, and storage silos)	196,000	1.3
Feed preparation (weigh feeders, conveyors, elevators, slurrying tank, agitator, and pumps)	243,000	1.6
Sulfur dioxide scrubbers and ducts (4 scrubbers including common feed plenum, mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fan)	4,906,000	32.8
Stack gas reheat (4 direct oil-fired reheaters)	431,000	2.9
Fans (4 fans including exhaust gas ducts and dampers between fan and stack gas plenum)	708,000	4.7
Slurry processing (screens, tanks, pumps, agitators and heating coils, centrifuges, conveyors, and elevators)	726,000	4.8
Drying (fluid bed dryer, fans, combustion chamber, dust collectors, conveyors, elevators, and $MgSO_3$ storage silo)	991,000	6.6
Calcining (fluid bed calciner, fans, weigh feeders, conveyors, elevators, waste heat boiler, dust collectors, and recycle MgO storage silo)	1,130,000	7.6
Sulfuric acid plant (complete contact unit for sulfuric acid production including dry gas purification system)	3,261,000	21.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	284,000	1.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	431,000	2.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	942,000	6.3
Construction facilities	712,000	4.8
Subtotal direct investment	14,961,000	100.0
Engineering design and supervision	1,496,000	10.0
Construction field expense	1,496,000	10.0
Contractor fees	748,000	5.0
Contingency	1,346,000	9.0
Subtotal fixed investment	20,047,000	134.0
Allowance for startup and modifications	2,005,000	13.4
Interest during construction (8%/annum rate)	1,604,000	10.7
Total capital investment	23,656,000	158.1

[a] Basis:

Stack gas reheat to 175°F by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-149. Magnesia Slurry–Regeneration Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 113,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,108 tons	155.00/ton	171,700	1.77
Coke	787 tons	15.00/ton	11,800	0.12
Catalyst	1,856 liters	1.65/liter	3,100	0.03
Subtotal raw material			186,600	1.92
Conversion costs				
Operating labor and supervision	39,200 man-hr	8.00/man-hr	313,600	3.23
Utilities				
Fuel oil (No. 6)	9,399,000 gal	0.23/gal	2,161,800	22.25
Heat credit	20,900 MM Btu	-1.60/MM Btu	(33,400)	(0.34)
Process water	2,399,600 M gal	0.04/M gal	96,000	0.99
Electricity	58,990,000 kWh	0.017/kWh	1,002,800	10.32
Maintenance				
Labor and material, .06 x 14,961,000			897,700	9.24
Analyses			145,200	1.49
Subtotal conversion costs			4,583,700	47.18
Subtotal direct costs			4,770,300	49.10
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,524,700	36.27
Overhead				
Plant, 20% of conversion costs			916,700	9.44
Administrative and marketing, 11% of conversion costs			504,200	5.19
Subtotal indirect costs			4,945,600	50.90
Total annual operating cost			9,715,900	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	85.30	1.00	1.39	15.95	261.32

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 9,731,500 bbl/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $23,656,000; subtotal direct investment, $14,961,000.
Working capital, $844,200.

Table B-150

MAGNESIA SLURRY-REGENERATION PROCESS, 1000 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON.

FIXED INVESTMENT: $ 23656000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	9731500	37200	113900	8.00	12176900	911200	11265700	11265700
2	7000	60900000	9731500	37200	113900	8.00	12012900	911200	11101700	22367400
3	7000	60900000	9731500	37200	113900	8.00	11848900	911200	10937700	33305100
4	7000	60900000	9731500	37200	113900	8.00	11684900	911200	10773700	44078800
5	7000	60900000	9731500	37200	113900	8.00	11520900	911200	10609700	54688500
6	7000	60900000	9731500	37200	113900	8.00	11356900	911200	10445700	65134200
7	7000	60900000	9731500	37200	113900	8.00	11192900	911200	10281700	75415900
8	7000	60900000	9731500	37200	113900	8.00	11028900	911200	10117700	85533600
9	7000	60900000	9731500	37200	113900	8.00	10864900	911200	9953700	95487300
10	7000	60900000	9731500	37200	113900	8.00	10700900	911200	9789700	105277000
11	5000	43500000	6951100	26600	81400	8.00	8942700	651200	8291500	113568500
12	5000	43500000	6951100	26600	81400	8.00	8778700	651200	8127500	121696000
13	5000	43500000	6951100	26600	81400	8.00	8614700	651200	7963500	129659500
14	5000	43500000	6951100	26600	81400	8.00	8450600	651200	7799400	137458900
15	5000	43500000	6951100	26600	81400	8.00	8286600	651200	7635400	145094300
16	3500	30450000	4865800	18600	56900	8.00	6894000	455200	6438800	151533100
17	3500	30450000	4865800	18600	56900	8.00	6730000	455200	6274800	157807900
18	3500	30450000	4865800	18600	56900	8.00	6566000	455200	6110800	163918700
19	3500	30450000	4865800	18600	56900	8.00	6402000	455200	5946800	169865500
20	3500	30450000	4865800	18600	56900	8.00	6238000	455200	5782800	175648300
21	1500	13050000	2085300	8000	24400	8.00	4349000	195200	4153800	179802100
22	1500	13050000	2085300	8000	24400	8.00	4185000	195200	3989800	183791900
23	1500	13050000	2085300	8000	24400	8.00	4021000	195200	3825800	187617700
24	1500	13050000	2085300	8000	24400	8.00	3857000	195200	3661800	191279500
25	1500	13050000	2085300	8000	24400	8.00	3693000	195200	3497800	194777300
26	1500	13050000	2085300	8000	24400	8.00	3528900	195200	3333700	198111000
27	1500	13050000	2085300	8000	24400	8.00	3364900	195200	3169700	201280700
28	1500	13050000	2085300	8000	24400	8.00	3200900	195200	3005700	204286400
29	1500	13050000	2085300	8000	24400	8.00	3036900	195200	2841700	207128100
30	1500	13050000	2085300	8000	24400	8.00	2872900	195200	2677700	209805800
TOT	127500	1109250000	177252500	678000	2074500		226401800	16596000	209805800	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.28	0.10	1.18	
MILLS PER KILOWATT-HOUR							1.78	0.13	1.65	
CENTS PER MILLION BTU HEAT INPUT							20.41	1.50	18.91	
DOLLARS PER TON OF SULFUR REMOVED							333.93	24.48	309.45	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							93104400	7142000	85962400	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.22	0.09	1.13	
MILLS PER KILOWATT-HOUR							1.70	0.13	1.57	
CENTS PER MILLION BTU HEAT INPUT							19.51	1.50	18.01	
DOLLARS PER TON OF SULFUR REMOVED							319.29	24.49	294.80	

Table B-151. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(200-MW new, coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 1.9 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	129,000	1.4
Particulate scrubbers and inlet ducts (2 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	1,704,000	17.9
Sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	1,831,000	19.2
Stack gas reheat (2 indirect steam reheaters)	227,000	2.4
Fans (2 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	392,000	4.1
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, steam/air heater, fan, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	838,000	8.8
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	1,454,000	15.2
Sulfur dioxide reduction unit	1,785,000	18.7
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	123,000	1.3
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	125,000	1.3
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	471,000	4.9
Construction facilities	454,000	4.8
Subtotal direct investment	9,533,000	100.0
Engineering design and supervision	1,239,000	13.0
Construction field expense	1,239,000	13.0
Contractor fees	667,000	7.0
Contingency	1,049,000	11.0
Subtotal fixed investment	13,727,000	144.0
Allowance for startup and modifications	1,373,000	14.4
Interest during construction (8%/annum rate)	1,098,000	11.5
Total capital investment	16,198,000	169.9

[a] Basis:
Stack gas reheat to 175° by indirect steam reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-152. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW new coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; 13,370 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (lst stage neutralization)	54.8 tons	26.00/ton	1,400	0.02
Soda ash	3,800 tons	52.00/ton	197,600	3.31
Antioxidant	130,000 lb	2.00/lb	260,000	4.35
Catalyst			4,900	0.08
Subtotal raw materials			463,900	7.77
Conversion costs				
Operating labor and supervision	36,100 man-hr	8.00/man-hr	288,800	4.84
Utilities				
Natural gas	208,300 mcf	1.00/mcf	208,300	3.49
Steam	874,100 M lb	0.80/M lb	699,300	11.72
Heat credit	25,700 MM Btu	-0.60/MM Btu	(15,400)	(0.26)
Process water	4,070,000 M gal	0.03/M gal	122,100	2.04
Electricity	30,320,000 kWh	0.011/kWh	333,500	5.58
Maintenance				
Labor and material, .07 x 9,533,000			667,300	11.17
Analyses			58,200	0.97
Subtotal conversion costs			2,362,100	39.55
Subtotal direct costs			2,826,000	47.32
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,413,500	40.42
Overhead				
Plant, 20% of conversion costs			472,400	7.91
Administrative and marketing			259,800	4.35
Subtotal indirect costs			3,145,700	52.68
Total annual operating cost			5,971,700	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	446.65	11.13	4.27	46.36	407.07

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $16,198,000; subtotal direct investment, $9,533,000.
Working capital, $505,800.
Investment and operating cost for disposal of fly ash excluded.

Table B-153

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 200 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 16196000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	12880000	536700	14700	13400	5300	25.00	20.00	7656800	441000	7215800	7215800
2	7000	12880000	536700	14700	13400	5300	25.00	20.00	7544500	441000	7103500	14319300
3	7000	12880000	536700	14700	13400	5300	25.00	20.00	7432200	441000	6991200	21310500
4	7000	12880000	536700	14700	13400	5300	25.00	20.00	7319900	441000	6878900	28189400
5	7000	12880000	536700	14700	13400	5300	25.00	20.00	7207600	441000	6766600	34956000
6	7000	12880000	536700	14700	13400	5300	25.00	20.00	7095300	441000	6654300	41610300
7	7000	12880000	536700	14700	13400	5300	25.00	20.00	6983000	441000	6542000	48152300
8	7000	12880000	536700	14700	13400	5300	25.00	20.00	6870700	441000	6429700	54582000
9	7000	12880000	536700	14700	13400	5300	25.00	20.00	6758400	441000	6317400	60899400
10	7000	12880000	536700	14700	13400	5300	25.00	20.00	6646100	441000	6205100	67104500
11	5000	9200000	383300	10500	9600	3800	25.00	20.00	5656600	316000	5340600	72445100
12	5000	9200000	383300	10500	9600	3800	25.00	20.00	5544300	316000	5228300	77673400
13	5000	9200000	383300	10500	9600	3800	25.00	20.00	5432000	316000	5116000	82789400
14	5000	9200000	383300	10500	9600	3800	25.00	20.00	5319700	316000	5003700	87793100
15	5000	9200000	383300	10500	9600	3800	25.00	20.00	5207400	316000	4891400	92684500
16	3500	6440000	268300	7300	6700	2700	25.00	20.00	4411300	221500	4189800	96874300
17	3500	6440000	268300	7300	6700	2700	25.00	20.00	4299000	221500	4077500	100951800
18	3500	6440000	268300	7300	6700	2700	25.00	20.00	4186700	221500	3965200	104917000
19	3500	6440000	268300	7300	6700	2700	25.00	20.00	4074400	221500	3852900	108769900
20	3500	6440000	268300	7300	6700	2700	25.00	20.00	3962100	221500	3740600	112510500
21	1500	2760000	115000	3100	2900	1100	25.00	20.00	2868800	94500	2774300	115284800
22	1500	2760000	115000	3100	2900	1100	25.00	20.00	2756500	94500	2662000	117946800
23	1500	2760000	115000	3100	2900	1100	25.00	20.00	2644200	94500	2549700	120496500
24	1500	2760000	115000	3100	2900	1100	25.00	20.00	2531900	94500	2437400	122933900
25	1500	2760000	115000	3100	2900	1100	25.00	20.00	2419600	94500	2325100	125259000
26	1500	2760000	115000	3100	2900	1100	25.00	20.00	2307300	94500	2212800	127471800
27	1500	2760000	115000	3100	2900	1100	25.00	20.00	2195000	94500	2100500	129572300
28	1500	2760000	115000	3100	2900	1100	25.00	20.00	2082700	94500	1988200	131560500
29	1500	2760000	115000	3100	2900	1100	25.00	20.00	1970400	94500	1875900	133436400
30	1500	2760000	115000	3100	2900	1100	25.00	20.00	1858100	94500	1763600	135200000
TOT	127500	234600000	9775000	267000	244500	96500			143242500	8042500	135200000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									14.65	0.82	13.83	
MILLS PER KILOWATT-HOUR									5.62	0.32	5.30	
CENTS PER MILLION BTU HEAT INPUT									61.06	3.43	57.63	
DOLLARS PER TON OF SULFUR REMOVED									536.49	30.12	506.37	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									58503900	3458900	55045000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									13.91	0.82	13.09	
MILLS PER KILOWATT-HOUR									5.33	0.31	5.02	
CENTS PER MILLION BTU HEAT INPUT									57.95	3.42	54.53	
DOLLARS PER TON OF SULFUR REMOVED									508.29	30.05	478.24	

Table B-154. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(200-MW existing, coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 2.0 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	145,000	1.5
Sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and all ductwork between outlet of supplemental fans and stack gas plenum)	2,569,000	26.5
Stack gas reheat (2 direct oil-fired reheaters)	129,000	1.3
Fans (2 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fans)	548,000	5.6
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	913,000	9.4
Sulfur dioxide regeneration (evaporator-crystallizers, packaged boiler, heaters, condensers, strippers, compressers, tanks, agitators, and pumps)	1,780,000	18.4
Sulfur dioxide reduction unit	1,967,000	20.3
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	146,000	1.5
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from power plant)	483,000	5.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	548,000	5.7
Construction facilities	461,000	4.8
Subtotal direct investment	9,689,000	100.0
Engineering design and supervision	1,356,000	14.0
Construction field expense	1,453,000	15.0
Contractor fees	872,000	9.0
Contingency	1,163,000	12.0
Subtotal fixed investment	14,533,000	150.0
Allowance for startup and modifications	1,453,000	15.0
Interest during construction (8%/annum rate)	1,163,000	12.0
Total capital investment	17,149,000	177.0

[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 20 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-155. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 13,800 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	3,900 tons	52.00/ton	202,800	2.75
Antioxidant	133,900 lb	2.00/lb	267,800	3.63
Catalyst			5,100	0.07
Subtotal raw materials			475,700	6.45
Conversion costs				
Operating labor and supervision	36,100 man-hr	8.00/man-hr	288,800	3.91
Utilities				
Fuel oil (No. 6)	7,255,000 gal	0.23/gal	1,668,700	22.62
Natural gas	215,100 mcf	1.00/mcf	215,100	2.92
Heat credit	26,500 MM Btu	-0.60/MM Btu	(15,900)	(0.22)
Process water	4,202,300 M gal	0.03/M gal	126,100	1.71
Electricity	21,170,000 kWh	0.011/kWh	232,900	3.16
Maintenance				
Labor and material, .07 x 9,689,000			678,200	9.19
Analyses			58,200	0.79
Subtotal conversion costs			3,252,100	44.08
Subtotal direct costs			3,727,800	50.53
Indirect Costs				
Average capital charges at 15.9% of total capital investment			2,726,700	36.95
Overhead				
Plant, 20% of conversion costs			650,400	8.82
Administrative and marketing			272,800	3.70
Subtotal indirect costs			3,649,900	49.47
Total annual operating cost			7,377,700	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	534.62	13.31	5.27	55.47	486.98

[a] Basis:

Remaining life of power plant, 20 yr.
Coal burned, 554,200 tons/yr, 9,500 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $17,149,000; subtotal direct investment, $9,689,000.
Working capital, $653,500.
Investment and operating cost for disposal of fly ash excluded.

Table B-156

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 200 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 17149000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SODIUM SULFATE	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11	5000	9500000	395800	10800	9900	3900	25.00	20.00	7970300	325500	7644800	7644800
12	5000	9500000	395800	10800	9900	3900	25.00	20.00	7791900	325500	7466400	15111200
13	5000	9500000	395800	10800	9900	3900	25.00	20.00	7613600	325500	7288100	22399300
14	5000	9500000	395800	10800	9900	3900	25.00	20.00	7435200	325500	7109700	29509000
15	5000	9500000	395800	10800	9900	3900	25.00	20.00	7256900	325500	6931600	36440600
16	3500	6650000	277100	7600	6900	2700	25.00	20.00	6159700	226500	5933200	42373600
17	3500	6650000	277100	7600	6900	2700	25.00	20.00	5981300	226500	5754800	48128400
18	3500	6650000	277100	7600	6900	2700	25.00	20.00	5803000	226500	5576500	53704900
19	3500	6650000	277100	7600	6900	2700	25.00	20.00	5624600	226500	5398100	59103000
20	3500	6650000	277100	7600	6900	2700	25.00	20.00	5446300	226500	5219800	64322800
21	1500	2850000	118700	3200	3000	1200	25.00	20.00	3974500	99000	3875500	68198300
22	1500	2850000	118700	3200	3000	1200	25.00	20.00	3796100	99000	3697100	71895400
23	1500	2850000	118700	3200	3000	1200	25.00	20.00	3617800	99000	3518800	75414200
24	1500	2850000	118700	3200	3000	1200	25.00	20.00	3439400	99000	3340400	78754600
25	1500	2850000	118700	3200	3000	1200	25.00	20.00	3261100	99000	3162100	81916700
26	1500	2850000	118700	3200	3000	1200	25.00	20.00	3082700	99000	2983700	84900400
27	1500	2850000	118700	3200	3000	1200	25.00	20.00	2904300	99000	2805300	87705700
28	1500	2850000	118700	3200	3000	1200	25.00	20.00	2726000	99000	2627000	90332700
29	1500	2850000	118700	3200	3000	1200	25.00	20.00	2547600	99000	2448600	92781300
30	1500	2850000	118700	3200	3000	1200	25.00	20.00	2369300	99000	2270300	95051600
TOT	57500	109250000	4551500	124000	114000	45000			98801600	3750000	95051600	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									21.71	0.83	20.88	
MILLS PER KILOWATT-HOUR									8.59	0.32	8.27	
CENTS PER MILLION BTU HEAT INPUT									90.44	3.44	87.00	
DOLLARS PER TON OF SULFUR REMOVED									796.79	30.24	766.55	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									50569900	2001600	48568300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									20.78	0.82	19.96	
MILLS PER KILOWATT-HOUR									8.22	0.32	7.90	
CENTS PER MILLION BTU HEAT INPUT									86.57	3.43	83.14	
DOLLARS PER TON OF SULFUR REMOVED									761.59	30.14	731.45	

Table B-157. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 4.8 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	251,000	1.4
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between outlet of supplemental fans and stack gas plenum)	5,938,000	32.1
Stack gas reheat (4 direct oil-fired reheaters)	305,000	1.6
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fans)	1,238,000	6.7
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,593,000	8.6
Sulfur dioxide regeneration (evaporator-crystallizers, packaged boiler, heaters, condensers, strippers, compressers, tanks, agitators, and pumps)	3,304,000	17.9
Sulfur dioxide reduction unit	3,200,000	17.3
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	267,000	1.4
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from power plant)	752,000	4.1
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	766,000	4.1
Construction facilities	881,000	4.8
Subtotal direct investment	18,495,000	100.0
Engineering design and supervision	2,219,000	12.0
Construction field expense	2,404,000	13.0
Contractor fees	1,295,000	7.0
Contingency	2,034,000	11.0
Subtotal fixed investment	26,447,000	143.0
Allowance for startup and modifications	2,645,000	14.3
Interest during construction (8%/annum rate)	2,116,000	11.4
Total capital investment	31,208,000	168.7

[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-158. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 33,420 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	9,500 tons	52.00/ton	494,000	3.37
Antioxidant	324,100 lb	2.00/lb	648,200	4.42
Catalyst			12,300	0.08
Subtotal raw materials			1,154,500	7.87
Conversion costs				
Operating labor and supervision	46,500 man-hr	8.00/man-hr	372,000	2.54
Utilities				
Fuel oil (No. 6)	17,567,000 gal	0.23/gal	4,040,400	27.56
Natural gas	520,800 mcf	1.00/mcf	520,800	3.55
Heat credit	64,300 MM Btu	-0.60/MM Btu	(38,600)	(0.26)
Process water	10,174,400 M gal	0.02/M gal	203,500	1.39
Electricity	51,260,000 kWh	0.010/kWh	512,600	3.50
Maintenance				
Labor and material, .06 x 18,495,000			1,109,700	7.57
Analyses			109,900	0.75
Subtotal conversion costs			6,830,300	46.60
Subtotal direct costs			7,984,800	54.47
Indirect Costs				
Average capital charges at 15.3% of total capital investment			4,774,800	32.58
Overhead				
Plant, 20% of conversion costs			1,336,100	9.32
Administrative and marketing			532,300	3.63
Subtotal indirect costs			6,673,200	45.53
Total annual operating cost			14,658,000	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	438.60	10.92	4.19	45.52	399.62

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $31,208,000; subtotal direct investment, $18,495,000.
Working capital, $1,397,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-159

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 31208000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1												
2												
3												
4												
5												
6	7000	32200000	1341700	36700	33400	13300	25.00	20.00	17903700	1101000	16802700	16802700
7	7000	32200000	1341700	36700	33400	13300	25.00	20.00	17644000	1101000	16543000	33345700
8	7000	32200000	1341700	36700	33400	13300	25.00	20.00	17384400	1101000	16283400	49629100
9	7000	32200000	1341700	36700	33400	13300	25.00	20.00	17124700	1101000	16023700	65652800
10	7000	32200000	1341700	36700	33400	13300	25.00	20.00	16865100	1101000	15764100	81416900
11	5000	23000000	958300	26200	23900	9500	25.00	20.00	13989600	787500	13202100	94619000
12	5000	23000000	958300	26200	23900	9500	25.00	20.00	13730000	787500	12942500	107561500
13	5000	23000000	958300	26200	23900	9500	25.00	20.00	13470300	787500	12682800	120244300
14	5000	23000000	958300	26200	23900	9500	25.00	20.00	13210700	787500	12423200	132667500
15	5000	23000000	958300	26200	23900	9500	25.00	20.00	12951000	787500	12163500	144831000
16	3500	16100000	670800	18300	16700	6600	25.00	20.00	10690600	549500	10141100	154972100
17	3500	16100000	670800	18300	16700	6600	25.00	20.00	10431000	549500	9881500	164853600
18	3500	16100000	670800	18300	16700	6600	25.00	20.00	10171300	549500	9621800	174475400
19	3500	16100000	670800	18300	16700	6600	25.00	20.00	9911700	549500	9362200	183837600
20	3500	16100000	670800	18300	16700	6600	25.00	20.00	9652000	549500	9102500	192940100
21	1500	6900000	287500	7900	7200	2800	25.00	20.00	6620700	236000	6384700	199324800
22	1500	6900000	287500	7900	7200	2800	25.00	20.00	6361000	236000	6125000	205449800
23	1500	6900000	287500	7900	7200	2800	25.00	20.00	6101400	236000	5865400	211315200
24	1500	6900000	287500	7900	7200	2800	25.00	20.00	5841700	236000	5605700	216920900
25	1500	6900000	287500	7900	7200	2800	25.00	20.00	5582100	236000	5346100	222267000
26	1500	6900000	287500	7900	7200	2800	25.00	20.00	5322400	236000	5086400	227353400
27	1500	6900000	287500	7900	7200	2800	25.00	20.00	5062800	236000	4826800	232180200
28	1500	6900000	287500	7900	7200	2800	25.00	20.00	4803100	236000	4567100	236747300
29	1500	6900000	287500	7900	7200	2800	25.00	20.00	4543500	236000	4307500	241054800
30	1500	6900000	287500	7900	7200	2800	25.00	20.00	4283900	236000	4047900	245102700
TOT	92500	425500000	17729000	485000	442000	175000			259652700	14550000	245102700	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									14.65	0.83	13.82	
MILLS PER KILOWATT-HOUR									5.61	0.31	5.30	
CENTS PER MILLION BTU HEAT INPUT									61.02	3.42	57.60	
DOLLARS PER TON OF SULFUR REMOVED									535.37	30.00	505.37	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									121163000	7177500	113985500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									13.86	0.83	13.03	
MILLS PER KILOWATT-HOUR									5.31	0.31	5.00	
CENTS PER MILLION BTU HEAT INPUT									57.73	3.42	54.31	
DOLLARS PER TON OF SULFUR REMOVED									506.75	30.02	476.73	

Table B-160. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; 2.7 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	159,000	1.0
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,846,000	23.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	4,269,000	25.8
Stack gas reheat (4 indirect steam reheaters)	539,000	3.3
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	889,000	5.4
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, steam/air heater, fan, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,035,000	6.2
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	1,837,000	11.1
Sulfur dioxide reduction unit	2,147,000	13.0
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	155,000	0.9
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	195,000	1.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	662,000	4.0
Construction facilities	787,000	4.8
Subtotal direct investment	16,520,000	100.0
Engineering design and supervision	1,817,000	11.0
Construction field expense	1,817,000	11.0
Contractor fees	826,000	5.0
Contingency	1,652,000	10.0
Subtotal fixed investment	22,632,000	137.0
Allowance for startup and modifications	2,263,000	13.7
Interest during construction (8%/annum rate)	1,811,000	11.0
Total capital investment	26,706,000	161.7

[a] Basis:
Stack gas reheat to 175° by indirect steam reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-161. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; 18,680 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (Ist stage neutralization)	76.6 tons	26.00/ton	2,000	0.02
Soda ash	5,300 tons	52.00/ton	275,600	3.03
Antioxidant	181,200 lb	2.00/lb	362,400	3.98
Catalyst			6,900	0.08
Subtotal raw materials			646,900	7.11
Conversion costs				
Operating labor and supervision	38,600 man-hr	8.00/man-hr	308,800	3.39
Utilities				
Natural gas	291,100 mcf	1.00/mcf	291,100	3.20
Steam	1,401,600 M lb	0.70/M lb	981,100	10.78
Heat credit	35,900 MM Btu	-0.60/MM Btu	(21,500)	(0.24)
Process water	5,760,200 M gal	0.02/M gal	115,200	1.27
Electricity	65,230,000 kWh	0.010/kWh	652,300	7.17
Maintenance				
Labor and material, .06 x 16,520,000			991,200	10.89
Analyses			98,300	1.08
Subtotal conversion costs			3,416,500	37.54
Subtotal direct costs			4,063,400	44.65
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,979,200	43.71
Overhead				
Plant, 20% of conversion costs			683,300	7.51
Administrative and marketing			375,800	4.13
Subtotal indirect costs			5,038,300	55.35
Total annual operating cost			9,101,700	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	487.24	6.93	2.60	28.89	443.99

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $26,706,000; subtotal direct investment, $16,520,000.
Working capital, $726,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-162

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 2.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 26706000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SODIUM SULFATE	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	20500	18700	7400	25.00	20.00	11880000	615500	11264500	11264500
2	7000	31500000	1312500	20500	18700	7400	25.00	20.00	11694900	615500	11079400	22343900
3	7000	31500000	1312500	20500	18700	7400	25.00	20.00	11509700	615500	10894200	33238100
4	7000	31500000	1312500	20500	18700	7400	25.00	20.00	11324600	615500	10709100	43947200
5	7000	31500000	1312500	20500	18700	7400	25.00	20.00	11139600	615500	10523900	54471100
6	7000	31500000	1312500	20500	18700	7400	25.00	20.00	10954200	615500	10338700	64809800
7	7000	31500000	1312500	20500	18700	7400	25.00	20.00	10769100	615500	10153600	74963400
8	7000	31500000	1312500	20500	18700	7400	25.00	20.00	10583900	615500	9968400	84931800
9	7000	31500000	1312500	20500	18700	7400	25.00	20.00	10398800	615500	9783300	94715100
10	7000	31500000	1312500	20500	18700	7400	25.00	20.00	10213600	615500	9598100	104313200
11	5000	22500000	937500	14600	13300	5300	25.00	20.00	8751300	438500	8312800	112626000
12	5000	22500000	937500	14600	13300	5300	25.00	20.00	8566200	438500	8127700	120753700
13	5000	22500000	937500	14600	13300	5300	25.00	20.00	8381000	438500	7942500	128696200
14	5000	22500000	937500	14600	13300	5300	25.00	20.00	8195800	438500	7757300	136453500
15	5000	22500000	937500	14600	13300	5300	25.00	20.00	8010700	438500	7572200	144025700
16	3500	15750000	656200	10300	9300	3700	25.00	20.00	6832700	306500	6526200	150551900
17	3500	15750000	656200	10300	9300	3700	25.00	20.00	6647600	306500	6341100	156893000
18	3500	15750000	656200	10300	9300	3700	25.00	20.00	6462400	306500	6155900	163048900
19	3500	15750000	656200	10300	9300	3700	25.00	20.00	6277200	306500	5970700	169019600
20	3500	15750000	656200	10300	9300	3700	25.00	20.00	6092100	306500	5785600	174805200
21	1500	6750000	281200	4400	4000	1600	25.00	20.00	4489700	132000	4357700	179162900
22	1500	6750000	281200	4400	4000	1600	25.00	20.00	4304600	132000	4172600	183335500
23	1500	6750000	281200	4400	4000	1600	25.00	20.00	4119400	132000	3987400	187322900
24	1500	6750000	281200	4400	4000	1600	25.00	20.00	3934200	132000	3802200	191125100
25	1500	6750000	281200	4400	4000	1600	25.00	20.00	3749100	132000	3617100	194742200
26	1500	6750000	281200	4400	4000	1600	25.00	20.00	3563900	132000	3431900	198174100
27	1500	6750000	281200	4400	4000	1600	25.00	20.00	3378700	132000	3246700	201420800
28	1500	6750000	281200	4400	4000	1600	25.00	20.00	3193600	132000	3061600	204482400
29	1500	6750000	281200	4400	4000	1600	25.00	20.00	3008400	132000	2876400	207358800
30	1500	6750000	281200	4400	4000	1600	25.00	20.00	2823300	132000	2691300	210050100
TOT	127500	573750000	23905500	373500	340000	135000			221250100	11200000	210050100	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									9.26	0.47	8.79	
MILLS PER KILOWATT-HOUR									3.47	0.18	3.29	
CENTS PER MILLION BTU HEAT INPUT									38.56	1.95	36.61	
DOLLARS PER TON OF SULFUR REMOVED									592.37	29.99	562.38	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									90426500	4821600	85604900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									8.79	0.47	8.32	
MILLS PER KILOWATT-HOUR									3.30	0.18	3.12	
CENTS PER MILLION BTU HEAT INPUT									36.63	1.96	34.67	
DOLLARS PER TON OF SULFUR REMOVED									562.70	30.00	532.70	

Table B-163. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 4.7 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	225,000	1.2
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,846,000	20.4
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	4,269,000	22.6
Stack gas reheat (4 indirect steam reheaters)	539,000	2.9
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	889,000	4.7
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, steam/air heater, fan, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,473,000	7.8
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	2,717,000	14.4
Sulfur dioxide reduction unit	2,921,000	15.5
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	227,000	1.2
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	195,000	1.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	662,000	3.5
Construction facilities	898,000	4.8
Subtotal direct investment	18,861,000	100.0
Engineering design and supervision	2,075,000	11.0
Construction field expense	2,075,000	11.0
Contractor fees	943,000	5.0
Contingency	1,886,000	10.0
Subtotal fixed investment	25,840,000	137.0
Allowance for startup and modifications	2,584,000	13.7
Interest during construction (8%/annum rate)	2,067,000	11.0
Total capital investment	30,491,000	161.7

[a] Basis:

Stack gas reheat to 175°by indirect steam reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-164. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 32,700 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (Ist stage neutralization)	134.1 tons	26.00/ton	3,500	0.03
Soda ash	9,300 tons	52.00/ton	483,600	4.17
Antioxidant	317,100 lb	2.00/lb	634,200	5.47
Catalyst			12,000	0.10
Subtotal raw materials			1,133,300	9.77
Conversion costs				
Operating labor and supervision	46,500 man-hr	8.00/man-hr	372,000	3.21
Utilities				
Natural gas	509,500 mcf	1.00/mcf	509,500	4.39
Steam	2,137,800 M lb	0.70/M lb	1,496,500	12.90
Heat credit	62,900 MM Btu	-0.60/MM Btu	(37,700)	(0.33)
Process water	9,953,400 M gal	0.02/M gal	199,100	1.72
Electricity	74,190,000 kWh	0.010/kWh	741,900	6.39
Maintenance				
Labor and material, .06 x 18,861,000			1,131,700	9.75
Analyses			109,900	0.95
Subtotal conversion costs			4,522,900	38.98
Subtotal direct costs			5,656,200	48.75
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,543,200	39.16
Overhead				
Plant, 20% of conversion costs			904,600	7.80
Administrative and marketing			497,500	4.29
Subtotal indirect costs			5,945,300	51.25
Total annual operating cost			11,601,500	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	354.79	8.84	3.31	36.83	323.34

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $30,491,000; subtotal direct investment, $18,861,000.
Working capital, $1,015,500.
Investment and operating cost for disposal of fly ash excluded.

Table B-165

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 30491000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SODIUM SULFATE	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	35900	32700	13000	25.00	20.00	14773500	1077500	13696000	13696000
2	7000	31500000	1312500	35900	32700	13000	25.00	20.00	14562100	1077500	13484600	27180600
3	7000	31500000	1312500	35900	32700	13000	25.00	20.00	14350700	1077500	13273200	40453800
4	7000	31500000	1312500	35900	32700	13000	25.00	20.00	14139300	1077500	13061800	53515600
5	7000	31500000	1312500	35900	32700	13000	25.00	20.00	13927900	1077500	12850400	66366000
6	7000	31500000	1312500	35900	32700	13000	25.00	20.00	13716500	1077500	12639000	79005000
7	7000	31500000	1312500	35900	32700	13000	25.00	20.00	13505100	1077500	12427600	91432600
8	7000	31500000	1312500	35900	32700	13000	25.00	20.00	13293600	1077500	12216100	103648700
9	7000	31500000	1312500	35900	32700	13000	25.00	20.00	13082200	1077500	12004700	115653400
10	7000	31500000	1312500	35900	32700	13000	25.00	20.00	12870800	1077500	11793300	127446700
11	5000	22500000	937500	25600	23400	9300	25.00	20.00	10858800	771000	10087800	137534500
12	5000	22500000	937500	25600	23400	9300	25.00	20.00	10647400	771000	9876400	147410900
13	5000	22500000	937500	25600	23400	9300	25.00	20.00	10436000	771000	9665000	157075900
14	5000	22500000	937500	25600	23400	9300	25.00	20.00	10224600	771000	9453600	166529500
15	5000	22500000	937500	25600	23400	9300	25.00	20.00	10013200	771000	9242200	175771700
16	3500	15750000	656200	17900	16300	6500	25.00	20.00	8410800	537500	7873300	183645000
17	3500	15750000	656200	17900	16300	6500	25.00	20.00	8199300	537500	7661800	191306800
18	3500	15750000	656200	17900	16300	6500	25.00	20.00	7987900	537500	7450400	198757200
19	3500	15750000	656200	17900	16300	6500	25.00	20.00	7776500	537500	7239000	205996200
20	3500	15750000	656200	17900	16300	6500	25.00	20.00	7565100	537500	7027600	213023800
21	1500	6750000	281200	7700	7000	2800	25.00	20.00	5391400	231000	5160400	218184200
22	1500	6750000	281200	7700	7000	2800	25.00	20.00	5180000	231000	4949000	223133200
23	1500	6750000	281200	7700	7000	2800	25.00	20.00	4968600	231000	4737600	227870800
24	1500	6750000	281200	7700	7000	2800	25.00	20.00	4757200	231000	4526200	232397000
25	1500	6750000	281200	7700	7000	2800	25.00	20.00	4545800	231000	4314800	236711800
26	1500	6750000	281200	7700	7000	2800	25.00	20.00	4334300	231000	4103300	240815100
27	1500	6750000	281200	7700	7000	2800	25.00	20.00	4122900	231000	3891900	244707000
28	1500	6750000	281200	7700	7000	2800	25.00	20.00	3911500	231000	3680500	248387500
29	1500	6750000	281200	7700	7000	2800	25.00	20.00	3700100	231000	3469100	251856600
30	1500	6750000	281200	7700	7000	2800	25.00	20.00	3488700	231000	3257700	255114300
TOT	127500	573750000	23905500	653500	595500	237000			274741800	19627500	255114300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									11.49	0.82	10.67	
MILLS PER KILOWATT-HOUR									4.31	0.31	4.00	
CENTS PER MILLION BTU HEAT INPUT									47.89	3.43	44.46	
DOLLARS PER TON OF SULFUR REMOVED									420.42	30.04	390.38	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									112738600	8446300	104292300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									10.96	0.82	10.14	
MILLS PER KILOWATT-HOUR									4.11	0.31	3.80	
CENTS PER MILLION BTU HEAT INPUT									45.66	3.42	42.24	
DOLLARS PER TON OF SULFUR REMOVED									400.78	30.03	370.75	

Table B-166. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; 6.7 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	281,000	1.3
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,846,000	18.4
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	4,269,000	20.5
Stack gas reheat (4 indirect steam reheaters)	539,000	2.6
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	889,000	4.3
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, steam/air heater, fan, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,844,000	8.8
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	3,489,000	16.7
Sulfur dioxide reduction unit	3,555,000	17.1
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	289,000	1.4
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	195,000	0.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	662,000	3.2
Construction facilities	993,000	4.8
Subtotal direct investment	20,851,000	100.0
Engineering design and supervision	2,294,000	11.0
Construction field expense	2,294,000	11.0
Contractor fees	1,043,000	5.0
Contingency	2,085,000	10.0
Subtotal fixed investment	28,567,000	137.0
Allowance for startup and modifications	2,857,000	13.7
Interest during construction (8%/annum rate)	2,285,000	11.0
Total capital investment	33,709,000	161.7

[a] Basis:

Stack gas reheat to 175° by indirect steam reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-167. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 5.0% S in fuel;
90% SO_2 removal; 46,710 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (lst stage neutralization)	191.5 tons	26.00/ton	5,000	0.04
Soda ash	13,300 tons	52.00/ton	691,600	4.95
Antioxidant	453,000 lb	2.00/lb	906,000	6.47
Catalyst			17,100	0.12
Subtotal raw materials			1,619,700	11.58
Conversion costs				
Operating labor and supervision	54,400 man-hr	8.00/man-hr	435,200	3.11
Utilities				
Natural gas	727,800 mcf	1.00/mcf	727,800	5.21
Steam	2,874,000 M lb	0.70/M lb	2,011,800	14.40
Heat credit	89,800 MM Btu	-0.60/MM Btu	(53,900)	(0.39)
Process water	14,146,700 M gal	0.02/M gal	282,900	2.02
Electricity	83,120,000 kWh	0.010/kWh	831,200	5.94
Maintenance				
Labor and material, .06 x 20,851,000			1,251,100	8.95
Analyses			117,700	0.84
Subtotal conversion costs			5,603,800	40.08
Subtotal direct costs			7,223,500	51.66
Indirect Costs				
Average capital charges at 14.9% of total capital investment			5,022,600	35.91
Overhead				
Plant, 20% of conversion costs			1,120,800	8.02
Administrative and marketing			616,400	4.41
Subtotal indirect costs			6,759,800	48.34
Total annual operating cost			13,983,300	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	299.36	10.65	4.00	44.39	272.79

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $33,709,000; subtotal direct investment, $20,851,000.
Working capital, $1,299,700.
Investment and operating cost for disposal of fly ash excluded.

Table B-168

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 5.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 33709000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	31500000	1312500	51300	46700	18600	25.00	20.00	17490200	1539500	15950700	15950700
2	7000	31500000	1312500	51300	46700	18600	25.00	20.00	17256500	1539500	15717000	31667700
3	7000	31500000	1312500	51300	46700	18600	25.00	20.00	17022800	1539500	15483300	47151000
4	7000	31500000	1312500	51300	46700	18600	25.00	20.00	16789000	1539500	15249500	62400500
5	7000	31500000	1312500	51300	46700	18600	25.00	20.00	16555300	1539500	15015800	77416300
6	7000	31500000	1312500	51300	46700	18600	25.00	20.00	16321600	1539500	14782100	92198400
7	7000	31500000	1312500	51300	46700	18600	25.00	20.00	16087900	1539500	14548400	106746800
8	7000	31500000	1312500	51300	46700	18600	25.00	20.00	15854200	1539500	14314700	121061500
9	7000	31500000	1312500	51300	46700	18600	25.00	20.00	15620500	1539500	14081000	135142500
10	7000	31500000	1312500	51300	46700	18600	25.00	20.00	15386800	1539500	13847300	148989800
11	5000	22500000	937500	36600	33400	13300	25.00	20.00	12836200	1101000	11735200	160725000
12	5000	22500000	937500	36600	33400	13300	25.00	20.00	12602500	1101000	11501500	172226500
13	5000	22500000	937500	36600	33400	13300	25.00	20.00	12368800	1101000	11267800	183494300
14	5000	22500000	937500	36600	33400	13300	25.00	20.00	12135100	1101000	11034100	194528400
15	5000	22500000	937500	36600	33400	13300	25.00	20.00	11901300	1101000	10800300	205328700
16	3500	15750000	656200	25600	23400	9300	25.00	20.00	9884200	771000	9113200	214441900
17	3500	15750000	656200	25600	23400	9300	25.00	20.00	9650500	771000	8879500	223321400
18	3500	15750000	656200	25600	23400	9300	25.00	20.00	9416800	771000	8645800	231967200
19	3500	15750000	656200	25600	23400	9300	25.00	20.00	9183100	771000	8412100	240379300
20	3500	15750000	656200	25600	23400	9300	25.00	20.00	8949400	771000	8178400	248557700
21	1500	6750000	281200	11000	10000	4000	25.00	20.00	6216500	330000	5886500	254444200
22	1500	6750000	281200	11000	10000	4000	25.00	20.00	5982800	330000	5652800	260097000
23	1500	6750000	281200	11000	10000	4000	25.00	20.00	5749100	330000	5419100	265516100
24	1500	6750000	281200	11000	10000	4000	25.00	20.00	5515400	330000	5185400	270701500
25	1500	6750000	281200	11000	10000	4000	25.00	20.00	5281700	330000	4951700	275653200
26	1500	6750000	281200	11000	10000	4000	25.00	20.00	5048000	330000	4718000	280371200
27	1500	6750000	281200	11000	10000	4000	25.00	20.00	4814200	330000	4484200	284855400
28	1500	6750000	281200	11000	10000	4000	25.00	20.00	4580500	330000	4250500	289105900
29	1500	6750000	281200	11000	10000	4000	25.00	20.00	4346800	330000	4016800	293122700
30	1500	6750000	281200	11000	10000	4000	25.00	20.00	4113100	330000	3783100	296905800
TOT	127500	573750000	23905500	934000	851000	339000			324960800	28055000	296905800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	13.59	1.17	12.42
MILLS PER KILOWATT-HOUR	5.10	0.44	4.66
CENTS PER MILLION BTU HEAT INPUT	56.64	4.89	51.75
DOLLARS PER TON OF SULFUR REMOVED	347.92	30.03	317.89
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	133730000	12069700	121660300
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	13.00	1.17	11.83
MILLS PER KILOWATT-HOUR	4.87	0.44	4.43
CENTS PER MILLION BTU HEAT INPUT	54.16	4.88	49.28
DOLLARS PER TON OF SULFUR REMOVED	332.66	30.02	302.64

Table B-169. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(1,000–MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 9.3 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	380,000	1.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between outlet of supplemental fans and stack gas plenum)	9,885,000	34.2
Stack gas reheat (4 direct oil-fired reheaters)	543,000	1.9
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fans)	1,891,000	6.6
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	2,432,000	8.4
Sulfur dioxide regeneration (evaporator-crystallizers, packaged boiler, heaters, condensers, strippers, compressers, tanks, agitators, and pumps)	5,289,000	18.3
Sulfur dioxide reduction unit	4,629,000	16.0
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	421,000	1.5
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from power plant)	1,052,000	3.6
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	989,000	3.4
Construction facilities	1,376,000	4.8
Subtotal direct investment	28,887,000	100.0
Engineering design and supervision	3,178,000	11.0
Construction field expense	3,466,000	12.0
Contractor fees	2,022,000	7.0
Contingency	2,889,000	10.0
Subtotal fixed investment	40,442,000	140.0
Allowance for startup and modifications	4,044,000	14.0
Interest during construction (8%/annum rate)	3,235,000	11.2
Total capital investment	47,721,000	165.2

[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for removal and disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-170. Sodium Solution—SO_2 Reduction Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(1,000-MW existing coal-fired power unit. 3.5% S in fuel; 90% SO_2 removal; 65,390 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	18,600 tons	52.00/ton	967,200	3.85
Antioxidant	634,200 lb	2.00/lb	1,268,400	5.05
Catalyst			24,000	0.10
Subtotal raw materials			2,259,600	9.00
Conversion costs				
Operating labor and supervision	56,900 man-hr	8.00/man-hr	455,200	1.81
Utilities				
Fuel oil (No. 6)	34,370,000 gal	0.23/gal	7,905,100	31.48
Natural gas	1,019,000 mcf	1.00/mcf	1,019,000	4.06
Heat credit	125,700 MM Btu	-0.60/MM Btu	(75,400)	(0.30)
Process water	19,906,800 M gal	0.02/M gal	398,100	1.58
Electricity	100,310,000 kWh	0.009/kWh	902,800	3.59
Maintenance				
Labor and material, .05 x 28,887,000			1,444,400	5.75
Analyses			181,100	0.72
Subtotal conversion costs			12,230,300	48.69
Subtotal direct costs			14,489,900	57.69
Indirect Costs				
Average capital charges at 15.3% of total capital investment			7,301,300	29.06
Overhead				
Plant, 20% of conversion costs			2,446,100	9.74
Administrative and marketing			881,200	3.51
Subtotal indirect costs			10,628,600	42.31
Total annual operating cost			25,118,500	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	384.13	9.57	3.59	39.87	350.03

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 2,625,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $47,721,000; subtotal direct investment, $28,887,000.
Working capital, $2,528,800.
Investment and operating cost for disposal of fly ash excluded.

Table B-171

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 1000 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 47721000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1												
2												
3												
4												
5												
6	7000	63000000	2625000	71800	65400	26000	25.00	20.00	30081500	2155000	27926500	27926500
7	7000	63000000	2625000	71800	65400	26000	25.00	20.00	29684400	2155000	27529400	55455900
8	7000	63000000	2625000	71800	65400	26000	25.00	20.00	29287400	2155000	27132400	82588300
9	7000	63000000	2625000	71800	65400	26000	25.00	20.00	28890400	2155000	26735400	109323700
10	7000	63000000	2625000	71800	65400	26000	25.00	20.00	28493300	2155000	26338300	135662000
11	5000	45000000	1875000	51300	46700	18600	25.00	20.00	23270500	1539500	21731000	157393000
12	5000	45000000	1875000	51300	46700	18600	25.00	20.00	22873500	1539500	21334000	178727000
13	5000	45000000	1875000	51300	46700	18600	25.00	20.00	22476500	1539500	20937000	199664000
14	5000	45000000	1875000	51300	46700	18600	25.00	20.00	22079400	1539500	20539900	220203900
15	5000	45000000	1875000	51300	46700	18600	25.00	20.00	21682400	1539500	20142900	240346800
16	3500	31500000	1312500	35900	32700	13000	25.00	20.00	17616200	1077500	16538700	256885500
17	3500	31500000	1312500	35900	32700	13000	25.00	20.00	17219100	1077500	16141600	273027100
18	3500	31500000	1312500	35900	32700	13000	25.00	20.00	16822100	1077500	15744600	288771700
19	3500	31500000	1312500	35900	32700	13000	25.00	20.00	16425100	1077500	15347600	304119300
20	3500	31500000	1312500	35900	32700	13000	25.00	20.00	16028000	1077500	14950500	319069800
21	1500	13500000	562500	15400	14000	5600	25.00	20.00	10606200	462000	10144200	329214000
22	1500	13500000	562500	15400	14000	5600	25.00	20.00	10209200	462000	9747200	338961200
23	1500	13500000	562500	15400	14000	5600	25.00	20.00	9812200	462000	9350200	348311400
24	1500	13500000	562500	15400	14000	5600	25.00	20.00	9415100	462000	8953100	357264500
25	1500	13500000	562500	15400	14000	5600	25.00	20.00	9018100	462000	8556100	365820600
26	1500	13500000	562500	15400	14000	5600	25.00	20.00	8621100	462000	8159100	373979700
27	1500	13500000	562500	15400	14000	5600	25.00	20.00	8224000	462000	7762000	381741700
28	1500	13500000	562500	15400	14000	5600	25.00	20.00	7827000	462000	7365000	389106700
29	1500	13500000	562500	15400	14000	5600	25.00	20.00	7430000	462000	6968000	396074700
30	1500	13500000	562500	15400	14000	5600	25.00	20.00	7032900	462000	6570900	402645600
TOT	92500	832500000	34687500	949000	864000	344000			431125600	28480000	402645600	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									12.43	0.82	11.61	
MILLS PER KILOWATT-HOUR									4.66	0.31	4.35	
CENTS PER MILLION BTU HEAT INPUT									51.79	3.42	48.37	
DOLLARS PER TON OF SULFUR REMOVED									454.29	30.01	424.28	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									202511600	14047200	188464400	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									11.84	0.83	11.01	
MILLS PER KILOWATT-HOUR									4.44	0.31	4.13	
CENTS PER MILLION BTU HEAT INPUT									49.32	3.42	45.90	
DOLLARS PER TON OF SULFUR REMOVED									432.72	30.02	402.70	

Table B-172. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 9.0 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	339,000	1.2
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	5,712,000	19.7
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	7,043,000	24.3
Stack gas reheat (4 indirect steam reheaters)	950,000	3.3
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	1,346,000	4.6
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, steam/air heater, fan, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	2,231,000	7.7
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	4,309,000	14.9
Sulfur dioxide reduction unit	4,197,000	14.5
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	355,000	1.2
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	272,000	0.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	851,000	2.9
Construction facilities	1,380,000	4.8
Subtotal direct investment	28,985,000	100.0
Engineering design and supervision	2,899,000	10.0
Construction field expense	2,899,000	10.0
Contractor fees	1,449,000	5.0
Contingency	2,609,000	9.0
Subtotal fixed investment	38,841,000	134.0
Allowance for startup and modifications	3,884,000	13.4
Interest during construction (8%/annum rate)	3,107,000	10.7
Total capital investment	45,832,000	158.1

[a] Basis:

Stack gas reheat to 175°by indirect steam reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-173. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 63,210 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (Ist stage neutralization)	259.2 tons	26.00/ton	6,700	0.04
Soda ash	18,000 tons	52.00/ton	936,000	5.09
Antioxidant	613,000 lb	2.00/lb	1,226,000	6.66
Catalyst			23,200	0.13
Subtotal raw materials			2,191,900	11.92
Conversion costs				
Operating labor and supervision	56,900 man-hr	8.00/man-hr	455,200	2.48
Utilities				
Natural gas	985,000 mcf	1.00/mcf	985,000	5.36
Steam	4,133,000 M lb	0.60/M lb	2,479,800	13.48
Heat credit	121,500 MM Btu	-0.60/MM Btu	(72,900)	(0.40)
Process water	19,242,900 M gal	0.02/M gal	384,900	2.09
Electricity	143,400,000 kWh	0.009/kWh	1,290,600	7.02
Maintenance				
Labor and material, .05 x 28,985,000			1,449,300	7.88
Analyses			181,100	0.98
Subtotal conversion costs			7,153,000	38.89
Subtotal direct costs			9,344,900	50.81
Indirect Costs				
Average capital charges at 14.9% of total capital investment			6,829,00	37.13
Overhead				
Plant, 20% of conversion costs			1,430,600	7.78
Administrative and marketing			786,800	4.28
Subtotal indirect costs			9,046,400	49.19
Total annual operating cost			18,391,300	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	290.96	7.25	2.63	30.20	265.12

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $45,832,000; subtotal direct investment, $28,985,000.
Working capital, $1,682,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-174

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 1000 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 45832000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	60900000	2537500	69400	63200	25100	25.00	20.00	23159300	2082000	21077300	21077300
2	7000	60900000	2537500	69400	63200	25100	25.00	20.00	22841500	2082000	20759500	41836800
3	7000	60900000	2537500	69400	63200	25100	25.00	20.00	22523700	2082000	20441700	62278500
4	7000	60900000	2537500	69400	63200	25100	25.00	20.00	22206000	2082000	20124000	82402500
5	7000	60900000	2537500	69400	63200	25100	25.00	20.00	21888200	2082000	19806200	102208700
6	7000	60900000	2537500	69400	63200	25100	25.00	20.00	21570400	2082000	19488400	121697100
7	7000	60900000	2537500	69400	63200	25100	25.00	20.00	21252700	2082000	19170700	140867800
8	7000	60900000	2537500	69400	63200	25100	25.00	20.00	20934900	2082000	18852900	159720700
9	7000	60900000	2537500	69400	63200	25100	25.00	20.00	20617200	2082000	18535200	178255900
10	7000	60900000	2537500	69400	63200	25100	25.00	20.00	20299400	2082000	18217400	196473300
11	5000	43500000	1812500	49600	45200	17900	25.00	20.00	16951600	1488000	15463600	211936900
12	5000	43500000	1812500	49600	45200	17900	25.00	20.00	16633900	1488000	15145900	227082800
13	5000	43500000	1812500	49600	45200	17900	25.00	20.00	16316100	1488000	14828100	241910900
14	5000	43500000	1612500	49600	45200	17900	25.00	20.00	15998400	1488000	14510400	256421300
15	5000	43500000	1612500	49600	45200	17900	25.00	20.00	15680600	1488000	14192600	270613900
16	3500	30450000	1268700	34700	31600	12600	25.00	20.00	13038300	1042000	11996300	282610200
17	3500	30450000	1268700	34700	31600	12600	25.00	20.00	12720600	1042000	11678600	294288800
18	3500	30450000	1258700	34700	31600	12600	25.00	20.00	12402800	1042000	11360800	305649600
19	3500	30450000	1268700	34700	31600	12600	25.00	20.00	12085000	1042000	11043000	316692600
20	3500	30450000	1268700	34700	31600	12600	25.00	20.00	11767300	1042000	10725300	327417900
21	1500	13050000	543700	14900	13500	5400	25.00	20.00	8214300	445500	7768800	335186700
22	1500	13050000	543700	14900	13500	5400	25.00	20.00	7896600	445500	7451100	342637800
23	1500	13050000	543700	14900	13500	5400	25.00	20.00	7578800	445500	7133300	349771100
24	1500	13050000	543700	14900	13500	5400	25.00	20.00	7261000	445500	6815500	356586600
25	1500	13050000	543700	14900	13500	5400	25.00	20.00	6943300	445500	6497800	363084400
26	1500	13050000	543700	14900	13500	5400	25.00	20.00	6625500	445500	6180000	369264400
27	1500	13050000	543700	14900	13500	5400	25.00	20.00	6307800	445500	5862300	375126700
28	1500	13050000	543700	14900	13500	5400	25.00	20.00	5990000	445500	5544500	380671200
29	1500	13050000	543700	14900	13500	5400	25.00	20.00	5672200	445500	5226700	385897900
30	1500	13050000	543700	14900	13500	5400	25.00	20.00	5354500	445500	4909000	390806900
TOT	127500	1109250000	46218000	1264500	1151000	457500			428731900	37925000	390806900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	9.28	0.82	8.46
MILLS PER KILOWATT-HOUR	3.36	0.29	3.07
CENTS PER MILLION BTU HEAT INPUT	38.65	3.42	35.23
DOLLARS PER TON OF SULFUR REMOVED	339.05	29.99	309.06
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	176695400	16320200	160375200
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	8.68	0.82	8.06
MILLS PER KILOWATT-HOUR	3.22	0.30	2.92
CENTS PER MILLION BTU HEAT INPUT	37.02	3.42	33.60
DOLLARS PER TON OF SULFUR REMOVED	324.81	30.00	294.81

Table B-175. Sodium Solution--SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 80% SO_2 removal; 4.2 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	209,000	1.1
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, and fly ash neutralization facilities)	3,840,000	21.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts to inlet of fan)	4,059,000	22.5
Stack gas reheat (4 indirect steam reheaters)	539,000	3.0
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	832,000	4.6
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, steam/air heater, fan, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,368,000	7.6
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	2,502,000	13.9
Sulfur dioxide reduction unit	2,738,000	15.2
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	209,000	1.2
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	195,000	1.1
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	662,000	3.7
Construction facilities	858,000	4.8
Subtotal direct investment	18,017,000	100.0
Engineering design and supervision	1,982,000	11.0
Construction field expense	1,982,000	11.0
Contractor fees	901,000	5.0
Contingency	1,802,00	10.0
Subtotal fixed investment	24,684,000	137.0
Allowance for startup and modifications	2,468,000	13.7
Interest during construction (8%/annum rate)	1,975,000	11.0
Total capital investment	29,127,000	161.7

[a] Basis:

Stack gas reheat to 175° by indirect steam reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-176. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new coal-fired power unit, 3.5% S in fuel;
80% SO_2 removal; 29,060 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (Ist stage neutralization)	134.1 tons	26.00/ton	3,500	0.03
Soda ash	8,200 tons	52.00/ton	426,400	3.94
Antioxidant	281,900 lb	2.00/lb	563,800	5.20
Catalyst			10,700	0.10
Subtotal raw materials			1,004,400	9.27
Conversion costs				
Operating labor and supervision	46,500 man-hr	8.00/man-hr	372,000	3.43
Utilities				
Natural gas	452,900 mcf	1.00/mcf	452,900	4.18
Steam	1,946,900 M lb	0.70/M lb	1,362,800	12.59
Heat credit	55,900 MM Btu	-0.60/MM Btu	(33,500)	(0.31)
Process water	9,060,200 M gal	0.02/M gal	181,200	1.67
Electricity	66,450,000 kWh	0.010/kWh	664,500	6.13
Maintenance				
Labor and material, .06 x 18,017,000			1,081,000	9.98
Analyses			109,900	1.01
Subtotal conversion costs			4,190,800	38.68
Subtotal direct costs			5,195,200	47.95
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,339,900	40.05
Overhead				
Plant, 20% of conversion costs			838,200	7.74
Administrative and marketing			461,000	4.26
Subtotal indirect costs			5,639,100	52.05
Total annual operating cost			10,834,300	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	372.83	8.25	3.10	34.39	339.74

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $29,127,000; subtotal direct investment, $18,017,000.
Working capital, $932,200.
Investment and operating cost for disposal of fly ash excluded.

Table B-177

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 80% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 29127000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	31500000	1312500	31900	29100	11600	25.00	20.00	13864500	959500	12905000	12905000
2	7000	31500000	1312500	31900	29100	11600	25.00	20.00	13662600	959500	12703100	25608100
3	7000	31500000	1312500	31900	29100	11600	25.00	20.00	13460600	959500	12501100	38109200
4	7000	31500000	1312500	31900	29100	11600	25.00	20.00	13258700	959500	12299200	50408400
5	7000	31500000	1312500	31900	29100	11600	25.00	20.00	13056700	959500	12097200	62505600
6	7000	31500000	1312500	31900	29100	11600	25.00	20.00	12854800	959500	11895300	74400900
7	7000	31500000	1312500	31900	29100	11600	25.00	20.00	12652800	959500	11693300	86094200
8	7000	31500000	1312500	31900	29100	11600	25.00	20.00	12450900	959500	11491400	97585600
9	7000	31500000	1312500	31900	29100	11600	25.00	20.00	12248900	959500	11289400	108875000
10	7000	31500000	1312500	31900	29100	11600	25.00	20.00	12047000	959500	11087500	119962500
11	5000	22500000	937500	22800	20800	8300	25.00	20.00	10198900	686000	9512900	129475400
12	5000	22500000	937500	22800	20800	8300	25.00	20.00	9997000	686000	9311000	138786400
13	5000	22500000	937500	22800	20800	8300	25.00	20.00	9795000	686000	9109000	147895400
14	5000	22500000	937500	22800	20800	8300	25.00	20.00	9593100	686000	8907100	156802500
15	5000	22500000	937500	22800	20800	8300	25.00	20.00	9391200	686000	8705200	165507700
16	3500	15750000	656200	15900	14500	5800	25.00	20.00	7915300	478500	7436800	172944500
17	3500	15750000	656200	15900	14500	5800	25.00	20.00	7713400	478500	7234900	180179400
18	3500	15750000	656200	15900	14500	5800	25.00	20.00	7511400	478500	7032900	187212300
19	3500	15750000	656200	15900	14500	5800	25.00	20.00	7309500	478500	6831000	194043300
20	3500	15750000	656200	15900	14500	5800	25.00	20.00	7107500	478500	6629000	200672300
21	1500	6750000	281200	6800	6200	2500	25.00	20.00	5102600	205000	4897600	205569900
22	1500	6750000	281200	6800	6200	2500	25.00	20.00	4900600	205000	4695600	210265500
23	1500	6750000	281200	6800	6200	2500	25.00	20.00	4698700	205000	4493700	214759200
24	1500	6750000	281200	6800	6200	2500	25.00	20.00	4496700	205000	4291700	219050900
25	1500	6750000	281200	6800	6200	2500	25.00	20.00	4294800	205000	4089800	223140700
26	1500	6750000	281200	6800	6200	2500	25.00	20.00	4092800	205000	3887800	227028500
27	1500	6750000	281200	6800	6200	2500	25.00	20.00	3890900	205000	3685900	230714400
28	1500	6750000	281200	6800	6200	2500	25.00	20.00	3688900	205000	3483900	234198300
29	1500	6750000	281200	6800	6200	2500	25.00	20.00	3487000	205000	3282000	237480300
30	1500	6750000	281200	6800	6200	2500	25.00	20.00	3285000	205000	3080000	240560300
TOT	127500	573750000	23905500	580500	529500	211500			258027800	17467500	240560300	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE)
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	10.79	0.73	10.06
MILLS PER KILOWATT-HOUR	4.05	0.28	3.77
CENTS PER MILLION BTU HEAT INPUT	44.97	3.04	41.93
DOLLARS PER TON OF SULFUR REMOVED	444.49	30.09	414.40
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	105764700	7519700	98245000
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	10.28	0.73	9.55
MILLS PER KILOWATT-HOUR	3.86	0.28	3.58
CENTS PER MILLION BTU HEAT INPUT	42.84	3.05	39.79
DOLLARS PER TON OF SULFUR REMOVED	423.06	30.08	392.98

Table B-178. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal, 4.8 tons/hr sulfur, particulate scrubber required for fly ash removal)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	251,000	1.1
Particulate scrubbers and inlet ducts (4 scrubbers including common feed plenum, effluent hold tanks, agitators, pumps, fly ash neutralization facilities, and all ductwork between outlet of supplemental fans and particulate scrubbers)	4,634,000	20.6
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and exhaust gas ducts between SO_2 scrubbers and stack gas plenum)	5,012,000	22.3
Stack gas reheat (4 direct oil-fired reheaters)	305,000	1.4
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fans)	1,340,000	6.0
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,593,000	7.1
Sulfur dioxide regeneration (evaporator-crystallizers, packaged boiler, heaters, condensers, strippers, compressers, tanks, agitators, and pumps)	3,304,000	14.6
Sulfur dioxide reduction unit	3,200,000	14.2
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	267,000	1.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water and electricity from power plant)	752,000	3.3
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	766,000	3.4
Construction facilities	1,071,000	4.8
Subtotal direct investment	22,495,000	100.0
Engineering design and supervision	2,699,000	12.0
Construction field expense	2,924,000	13.0
Contractor fees	1,575,000	7.0
Contingency	2,474,000	11.0
Subtotal fixed investment	32,167,000	143.0
Allowance for startup and modifications	3,217,000	14.3
Interest during construction (8%/annum rate)	2,573,000	11.4
Total capital investment	37,957,000	168.7

[a] Basis:

Stack gas reheat to 175° by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Remaining life of power unit, 25 yr.

Fly ash slurry neutralized before disposal; closed loop water utilization for first stage.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-179. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit. 3.5% S in fuel, 90% SO_2 removal; 33,420 tons/yr sulfur; particulate scrubber required for fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Lime (Ist stage neutralization)	137.0 tons	26.00/ton	3,600	0.02
Soda ash	9,500 tons	52.00/ton	494,000	3.01
Antioxidant	324,100 lb	2.00/lb	648,200	3.96
Catalyst			12,300	0.08
Subtotal raw materials			1,158,100	7.07
Conversion costs				
Operating labor and supervision	46,500 man-hr	8.00/man-hr	372,000	2.27
Utilities				
Fuel oil (No. 6)	17,567,000 gal	0.23/gal	4,040,400	24.65
Natural gas	520,800 mcf	1.00/mcf	520,800	3.18
Heat credit	64,300 MM Btu	-0.60/MM Btu	(38,600)	(0.24)
Process water	10,174,400 M gal	0.02/M gal	203,500	1.24
Electricity	79,790,000 kWh	0.010kWh	797,900	4.87
Maintenance				
Labor and material, .06 x 22,495,000			1,349,700	8.24
Analyses			109,900	0.67
Subtotal conversion costs			7,355,600	44.88
Subtotal direct costs			8,513,700	51.95
Indirect Costs				
Average capital charges at 15.3% of total capital investment			5,807,400	35.43
Overhead				
Plant, 20% of conversion costs			1,471,100	8.98
Administrative and marketing			597,000	3.64
Subtotal indirect costs			7,875,500	48.05
Total annual operating cost			16,389,200	100.00

	Dollars/ton product sulfur	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	490.40	12.22	4.68	50.90	446.82

[a] Basis:

Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $37,957,000, subtotal direct investment, $22,495,000.
Working capital, $1,491,300.
Investment and operating cost for disposal of fly ash excluded.

Table B-180

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW EXIST. COAL FIRED POWER UNIT, 3.5% S, 90% SO2 REMOVAL, FLYASH REMOVED BY PART. SCRUB

FIXED INVESTMENT: $ 37957000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1												
2												
3												
4												
5												
6	7000	32200000	1341700	36700	33400	13300	25.00	20.00	20336800	1101000	19235800	19235800
7	7000	32200000	1341700	36700	33400	13300	25.00	20.00	20020900	1101000	18919900	38155700
8	7000	32200000	1341700	36700	33400	13300	25.00	20.00	19705100	1101000	18604100	56759800
9	7000	32200000	1341700	36700	33400	13300	25.00	20.00	19389300	1101000	18288300	75048100
10	7000	32200000	1341700	36700	33400	13300	25.00	20.00	19073500	1101000	17972500	93020600
11	5000	23000000	958300	26200	23900	9500	25.00	20.00	15974500	787500	15187000	108207600
12	5000	23000000	958300	26200	23900	9500	25.00	20.00	15658700	787500	14871200	123078800
13	5000	23000000	958300	26200	23900	9500	25.00	20.00	15342900	787500	14555400	137634200
14	5000	23000000	958300	26200	23900	9500	25.00	20.00	15027100	787500	14239600	151873800
15	5000	23000000	958300	26200	23900	9500	25.00	20.00	14711300	787500	13923800	165797600
16	3500	16100000	670800	18300	16700	6600	25.00	20.00	12262800	549500	11713300	177510900
17	3500	16100000	670800	18300	16700	6600	25.00	20.00	11947000	549500	11397500	188908400
18	3500	16100000	670800	18300	16700	6600	25.00	20.00	11631200	549500	11081700	199990100
19	3500	16100000	670800	18300	16700	6600	25.00	20.00	11315400	549500	10765900	210756000
20	3500	16100000	670800	18300	16700	6600	25.00	20.00	10999600	549500	10450100	221206100
21	1500	6900000	287500	7900	7200	2800	25.00	20.00	7719600	236000	7483600	228689700
22	1500	6900000	287500	7900	7200	2800	25.00	20.00	7403800	236000	7167800	235857500
23	1500	6900000	287500	7900	7200	2800	25.00	20.00	7087900	236000	6851900	242709400
24	1500	6900000	287500	7900	7200	2800	25.00	20.00	6772100	236000	6536100	249245500
25	1500	6900000	287500	7900	7200	2800	25.00	20.00	6456300	236000	6220300	255465800
26	1500	6900000	287500	7900	7200	2800	25.00	20.00	6140500	236000	5904500	261370300
27	1500	6900000	287500	7900	7200	2800	25.00	20.00	5824700	236000	5588700	266959000
28	1500	6900000	287500	7900	7200	2800	25.00	20.00	5508900	236000	5272900	272231900
29	1500	6900000	287500	7900	7200	2800	25.00	20.00	5193100	236000	4957100	277189000
30	1500	6900000	287500	7900	7200	2800	25.00	20.00	4877300	236000	4641300	281830300
TOT	92500	425500000	17729000	485000	442000	175000			296380300	14550000	281830300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									16.72	0.82	15.90	
MILLS PER KILOWATT-HOUR									6.41	0.32	6.09	
CENTS PER MILLION BTU HEAT INPUT									69.65	3.41	66.24	
DOLLARS PER TON OF SULFUR REMOVED									611.09	30.00	581.09	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									137891400	7177500	130713900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									15.77	0.82	14.95	
MILLS PER KILOWATT-HOUR									6.04	0.31	5.73	
CENTS PER MILLION BTU HEAT INPUT									65.70	3.42	62.28	
DOLLARS PER TON OF SULFUR REMOVED									576.71	30.02	546.69	

Table B-181. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(200-MW new oil-fired power unit, 2.5% S in fuel,
90% SO_2 removal; 1.0 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	88,000	1.5
Sulfur dioxide scrubbers and ducts (2 scrubbers including mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fans)	1,826,000	30.1
Stack gas reheat (2 direct oil-fired reheaters)	103,000	1.7
Fans (2 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	261,000	4.3
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	556,000	9.2
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	935,000	15.4
Sulfur dioxide reduction unit	1,265,000	20.7
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	81,000	1.3
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	209,000	3.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	463,000	7.6
Construction facilities	289,000	4.8
Subtotal direct investment	6,076,000	100.0
Engineering design and supervision	790,000	13.0
Construction field expense	790,000	13.0
Contractor fees	425,000	7.0
Contingency	668,000	11.0
Subtotal fixed investment	8,749,000	144.0
Allowance for startup and modifications	875,000	14.4
Interest during construction (8%/annum rate)	700,00	11.5
Total capital investment	10,324,000	169.9

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[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974
Minimum in process storage; only pumps are spared
Construction labor shortages with accompanying overtime pay incentive not considered

Table B-182. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW new oil-fired power unit. 2.5% S in fuel,
90% SO_2 removal; 7,130 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	2,000 tons	52.00/ton	104,000	2.44
Antioxidant	69,200 lb	2.00/lb	138,400	3.24
Catalyst			2,600	0.06
Subtotal raw materials			245,000	5.74
Conversion costs				
Operating labor and supervision	33,600 man-hr	8.00/man-hr	268,800	6.30
Utilities				
Fuel oil (No. 6)	1,032,000 gal	0.23/gal	237,400	5.56
Natural gas	111,100 mcf	1.00/mcf	111,100	2.60
Steam	343,500 M lb	1.50/M lb	515,300	12.07
Heat credit	13,700 MM Btu	-1.60/MM Btu	(21,900)	(0.51)
Process water	2,170,900 M gal	0.04/M gal	86,800	2.03
Electricity	13,500,000 kWh	0.019/kWh	256,500	6.01
Maintenance				
Labor and material, .07 x 6,076,000			425,300	9.96
Analyses			38,800	0.91
Subtotal conversion costs			1,918,100	44.93
Subtotal direct costs			2,163,100	50.67
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,538,300	36.03
Overhead				
Plant, 20% of conversion costs			383,600	8.99
Administrative and marketing			184,200	4.31
Subtotal indirect costs			2,106,100	49.33
Total annual operating cost			4,269,200	100.00

	Dollars/ton product sulfur	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	598.77	2.07	3.05	33.15	545.24

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,058,200 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $10,324,000; subtotal direct investment, $6,076,000.
Working capital, $381,800.

Table B-183

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 200 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 10324000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SODIUM SULFATE	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	2058200	7800	7100	2800	25.00	20.00	5343200	233500	5109700	5109700
2	7000	12880000	2058200	7800	7100	2800	25.00	20.00	5271600	233500	5038100	10147800
3	7000	12880000	2058200	7800	7100	2800	25.00	20.00	5200000	233500	4966500	15114300
4	7000	12880000	2058200	7800	7100	2800	25.00	20.00	5128500	233500	4895000	20009300
5	7000	12880000	2058200	7800	7100	2800	25.00	20.00	5056900	233500	4823400	24832700
6	7000	12880000	2058200	7800	7100	2800	25.00	20.00	4985300	233500	4751800	29584500
7	7000	12880000	2058200	7800	7100	2800	25.00	20.00	4913800	233500	4680300	34264800
8	7000	12880000	2058200	7800	7100	2800	25.00	20.00	4842200	233500	4608700	38873500
9	7000	12880000	2058200	7800	7100	2800	25.00	20.00	4770600	233500	4537100	43410600
10	7000	12880000	2058200	7800	7100	2800	25.00	20.00	4699000	233500	4465500	47876100
11	5000	9200000	1470100	5600	5100	2000	25.00	20.00	3949400	167500	3781900	51658000
12	5000	9200000	1470100	5600	5100	2000	25.00	20.00	3877800	167500	3710300	55368300
13	5000	9200000	1470100	5600	5100	2000	25.00	20.00	3806200	167500	3638700	59007000
14	5000	9200000	1470100	5600	5100	2000	25.00	20.00	3734600	167500	3567100	62574100
15	5000	9200000	1470100	5600	5100	2000	25.00	20.00	3663100	167500	3495600	66069700
16	3500	6440000	1029100	3900	3600	1400	25.00	20.00	3064400	118000	2946400	69016100
17	3500	6440000	1029100	3900	3600	1400	25.00	20.00	2992800	118000	2874800	71890900
18	3500	6440000	1029100	3900	3600	1400	25.00	20.00	2921300	118000	2803300	74694200
19	3500	6440000	1029100	3900	3600	1400	25.00	20.00	2849700	118000	2731700	77425900
20	3500	6440000	1029100	3900	3600	1400	25.00	20.00	2778100	118000	2660100	80086000
21	1500	2760000	441000	1700	1500	600	25.00	20.00	1953300	49500	1903800	81989800
22	1500	2760000	441000	1700	1500	600	25.00	20.00	1881800	49500	1832300	83822100
23	1500	2760000	441000	1700	1500	600	25.00	20.00	1810200	49500	1760700	85582800
24	1500	2760000	441000	1700	1500	600	25.00	20.00	1738600	49500	1689100	87271900
25	1500	2760000	441000	1700	1500	600	25.00	20.00	1667000	49500	1617500	88889400
26	1500	2760000	441000	1700	1500	600	25.00	20.00	1595500	49500	1546000	90435400
27	1500	2760000	441000	1700	1500	600	25.00	20.00	1523900	49500	1474400	91909800
28	1500	2760000	441000	1700	1500	600	25.00	20.00	1452300	49500	1402800	93312600
29	1500	2760000	441000	1700	1500	600	25.00	20.00	1380800	49500	1331300	94643900
30	1500	2760000	441000	1700	1500	600	25.00	20.00	1309200	49500	1259700	95903600
TOT	127500	234600000	37488000	142500	129500	51000			100161100	4257500	95903600	

	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	2.67	0.11	2.56
MILLS PER KILOWATT-HOUR	3.93	0.17	3.76
CENTS PER MILLION BTU HEAT INPUT	42.69	1.81	40.88
DOLLARS PER TON OF SULFUR REMOVED	702.88	29.87	673.01
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	40979700	1831800	39147900
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	2.54	0.11	2.43
MILLS PER KILOWATT-HOUR	3.73	0.16	3.57
CENTS PER MILLION BTU HEAT INPUT	40.59	1.81	38.78
DOLLARS PER TON OF SULFUR REMOVED	669.60	29.93	639.67

Table B-184. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal, 1.0 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	86,000	0.9
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fans)	4,253,000	45.3
Stack gas reheat (4 direct oil-fired reheaters)	245,000	2.6
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	594,000	6.3
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	549,000	5.8
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	921,000	9.8
Sulfur dioxide reduction unit	1,250,000	13.3
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	79,000	0.8
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	327,000	3.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	650,000	6.9
Construction facilities	448,000	4.8
Subtotal direct investment	9,402,000	100.0
Engineering design and supervision	1,034,000	11.0
Construction field expense	1,034,000	11.0
Contractor fees	470,000	5.0
Contingency	940,000	10.0
Subtotal fixed investment	12,880,000	137.0
Allowance for startup and modifications	1,288,000	13.6
Interest during construction (8%/annum rate)	1,030,000	11.0
Total capital investment	15,198,000	161.6

[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-185. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; 6,970 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	2,000 tons	52.00/ton	104,000	1.78
Antioxidant	67,600 lb	2.00/lb	135,200	2.31
Catalyst			2,600	0.04
Subtotal raw materials			241,800	4.13
Conversion costs				
Operating labor and supervision	36,100 man-hr	8.00/man-hr	288,800	4.93
Utilities				
Fuel oil (No. 6)	2,329,000 gal	0.23/gal	535,700	9.15
Natural gas	108,700 mcf	1.00/mcf	108,700	1.86
Steam	335,900 M lb	1.40/M lb	470,300	8.03
Heat credit	13,400 MM Btu	-1.60/MM Btu	(21,400)	(0.37)
Process water	2,177,500 M gal	0.04/M gal	87,100	1.49
Electricity	26,340,000 kWh	0.018kWh	474,100	8.10
Maintenance				
Labor and material, .06 x 9,402,000			564,100	9.63
Analyses			71,200	1.22
Subtotal conversion costs			2,578,600	44.04
Subtotal direct costs			2,820,400	48.17
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,264,500	38.68
Overhead				
Plant, 20% of conversion costs			515,700	8.81
Administrative and marketing			254,100	4.34
Subtotal indirect costs			3,034,300	51.83
Total annual operating cost			5,854,700	100.00

	Dollars/ton product sulfur	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	839.99	1.16	1.67	18.59	765.32

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $15,198,000; subtotal direct investment, $9,402,000.
Working capital, $497,200.

Table B-186

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 1.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 15198000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	31500000	5033600	7700	7000	2800	25.00	20.00	7435800	231000	7204800	7204800
2	7000	31500000	5033600	7700	7000	2800	25.00	20.00	7330400	231000	7099400	14304200
3	7000	31500000	5033600	7700	7000	2800	25.00	20.00	7225000	231000	6994000	21298200
4	7000	31500000	5033600	7700	7000	2800	25.00	20.00	7119700	231000	6888700	28186900
5	7000	31500000	5033600	7700	7000	2800	25.00	20.00	7014300	231000	6783300	34970200
6	7000	31500000	5033600	7700	7000	2800	25.00	20.00	6908900	231000	6677900	41648100
7	7000	31500000	5033600	7700	7000	2800	25.00	20.00	6803500	231000	6572500	48220600
8	7000	31500000	5033600	7700	7000	2800	25.00	20.00	6698200	231000	6467200	54687800
9	7000	31500000	5033600	7700	7000	2800	25.00	20.00	6592800	231000	6361800	61049600
10	7000	31500000	5033600	7700	7000	2800	25.00	20.00	6487400	231000	6256400	67306000
11	5000	22500000	3595400	5500	5000	2000	25.00	20.00	5480700	165000	5315700	72621700
12	5000	22500000	3595400	5500	5000	2000	25.00	20.00	5375300	165000	5210300	77832000
13	5000	22500000	3595400	5500	5000	2000	25.00	20.00	5269900	165000	5104900	82936900
14	5000	22500000	3595400	5500	5000	2000	25.00	20.00	5164500	165000	4999500	87936400
15	5000	22500000	3595400	5500	5000	2000	25.00	20.00	5059200	165000	4894200	92830600
16	3500	15750000	2516800	3800	3500	1400	25.00	20.00	4254900	115500	4139400	96970000
17	3500	15750000	2516800	3800	3500	1400	25.00	20.00	4149500	115500	4034000	101004000
18	3500	15750000	2516800	3800	3500	1400	25.00	20.00	4044100	115500	3928600	104932600
19	3500	15750000	2516800	3800	3500	1400	25.00	20.00	3938800	115500	3823300	108755900
20	3500	15750000	2516800	3800	3500	1400	25.00	20.00	3833400	115500	3717900	112473800
21	1500	6750000	1078600	1600	1500	600	25.00	20.00	2734500	49500	2685000	115158800
22	1500	6750000	1078600	1600	1500	600	25.00	20.00	2629200	49500	2579700	117738500
23	1500	6750000	1078600	1600	1500	600	25.00	20.00	2523800	49500	2474300	120212800
24	1500	6750000	1078600	1600	1500	600	25.00	20.00	2418400	49500	2368900	122581700
25	1500	6750000	1078600	1600	1500	600	25.00	20.00	2313000	49500	2263500	124845200
26	1500	6750000	1078600	1600	1500	600	25.00	20.00	2207700	49500	2158200	127003400
27	1500	6750000	1078600	1600	1500	600	25.00	20.00	2102300	49500	2052800	129056200
28	1500	6750000	1078600	1600	1500	600	25.00	20.00	1996900	49500	1947400	131003600
29	1500	6750000	1078600	1600	1500	600	25.00	20.00	1891500	49500	1842000	132845600
30	1500	6750000	1078600	1600	1500	600	25.00	20.00	1786200	49500	1736700	134582300
TOT	127500	573750000	91683000	139500	127500	51000			138789800	4207500	134582300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.51	0.04	1.47
MILLS PER KILOWATT-HOUR	2.18	0.07	2.11
CENTS PER MILLION BTU HEAT INPUT	24.19	0.73	23.46
DOLLARS PER TON OF SULFUR REMOVED	994.91	30.16	964.75
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	56836000	1810600	55025400
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.44	0.05	1.39
MILLS PER KILOWATT-HOUR	2.07	0.06	2.01
CENTS PER MILLION BTU HEAT INPUT	23.02	0.73	22.29
DOLLARS PER TON OF SULFUR REMOVED	944.12	30.08	914.04

Table B-187. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 2.5 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	152,000	1.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fans)	4,253,000	36.3
Stack gas reheat (4 direct oil-fired reheaters)	245,000	2.1
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	594,000	5.1
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	977,000	8.3
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	1,750,000	14.9
Sulfur dioxide reduction unit	2,068,000	17.6
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	148,000	1.3
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	327,000	2.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	650,000	5.5
Construction facilities	558,000	4.8
Subtotal direct investment	11,722,000	100.0
Engineering design and supervision	1,289,000	11.0
Construction field expense	1,289,000	11.0
Contractor fees	586,000	5.0
Contingency	1,172,00	10.0
Subtotal fixed investment	16,058,000	137.0
Allowance for startup and modifications	1,606,000	13.7
Interest during construction (8%/annum rate)	1,285,000	11.0
Total capital investment	18,949,000	161.7

[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-188. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 2.5% S in fuel;
90% SO_2 removal; 17,440 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	5,000 tons	52.00/ton	260,000	3.13
Antioxidant	169,100 lb	2.00/lb	338,200	4.07
Catalyst			6,400	0.08
Subtotal raw materials			604,600	7.28
Conversion costs				
Operating labor and supervision	38,600 man-hr	8.00/man-hr	308,800	3.72
Utilities				
Fuel oil (No. 6)	2,524,000 gal	0.23/gal	580,500	6.99
Natural gas	271,700 mcf	1.00/mcf	271,700	3.27
Steam	839,900 M lb	1.40/M lb	1,175,900	14.16
Heat credit	33,500 MM Btu	-1.60/MM Btu	(53,600)	(0.65)
Process water	5,308,200 M gal	0.02/M gal	106,200	1.28
Electricity	33,000,000 kWh	0.018/kWh	594,000	7.15
Maintenance				
Labor and material, .06 x 11,722,000			703,300	8.47
Analyses			85,300	1.03
Subtotal conversion costs			3,772,100	45.42
Subtotal direct costs			4,376,700	52.70
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,823,400	34.00
Overhead				
Plant, 20% of conversion costs			754,400	9.08
Administrative and marketing			350,600	4.22
Subtotal indirect costs			3,928,400	47.30
Total annual operating cost			8,305,100	100.00

	Dollars/ton product sulfur	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	476.21	1.65	2.37	26.37	434.14

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $18,949,000; subtotal direct investment, $11,722,000.
Working capital, $772,800.

Table B-189

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 18949000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	31500000	5033600	19100	17400	6900	25.00	20.00	10276400	573000	9703400	9703400
2	7000	31500000	5033600	19100	17400	6900	25.00	20.00	10145000	573000	9572000	19275400
3	7000	31500000	5033600	19100	17400	6900	25.00	20.00	10013600	573000	9440600	28716000
4	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9882300	573000	9309300	38025300
5	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9750900	573000	9177900	47203200
6	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9619500	573000	9046500	56249700
7	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9488200	573000	8915200	65164900
8	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9356800	573000	8783800	73948700
9	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9225400	573000	8652400	82601100
10	7000	31500000	5033600	19100	17400	6900	25.00	20.00	9094000	573000	8521000	91122100
11	5000	22500000	3595400	13700	12500	5000	25.00	20.00	7542300	412500	7129800	98251900
12	5000	22500000	3595400	13700	12500	5000	25.00	20.00	7410900	412500	6998400	105250300
13	5000	22500000	3595400	13700	12500	5000	25.00	20.00	7279500	412500	6867000	112117300
14	5000	22500000	3595400	13700	12500	5000	25.00	20.00	7148100	412500	6735600	118852900
15	5000	22500000	3595400	13700	12500	5000	25.00	20.00	7016800	412500	6604300	125457200
16	3500	15750000	2516800	9600	8700	3500	25.00	20.00	5793100	287500	5505600	130962800
17	3500	15750000	2516800	9600	8700	3500	25.00	20.00	5661700	287500	5374200	136337000
18	3500	15750000	2516800	9600	8700	3500	25.00	20.00	5530400	287500	5242900	141579900
19	3500	15750000	2516800	9600	8700	3500	25.00	20.00	5399000	287500	5111500	146691400
20	3500	15750000	2516800	9600	8700	3500	25.00	20.00	5267600	287500	4980100	151671500
21	1500	6750000	1078600	4100	3700	1500	25.00	20.00	3607100	122500	3484600	155156100
22	1500	6750000	1078600	4100	3700	1500	25.00	20.00	3475800	122500	3353300	158509400
23	1500	6750000	1078600	4100	3700	1500	25.00	20.00	3344400	122500	3221900	161731300
24	1500	6750000	1078600	4100	3700	1500	25.00	20.00	3213000	122500	3090500	164821800
25	1500	6750000	1078600	4100	3700	1500	25.00	20.00	3081600	122500	2959100	167780900
26	1500	6750000	1078600	4100	3700	1500	25.00	20.00	2950300	122500	2827800	170608700
27	1500	6750000	1078600	4100	3700	1500	25.00	20.00	2818900	122500	2696400	173305100
28	1500	6750000	1078600	4100	3700	1500	25.00	20.00	2687500	122500	2565000	175870100
29	1500	6750000	1078600	4100	3700	1500	25.00	20.00	2556200	122500	2433700	178303800
30	1500	6750000	1078600	4100	3700	1500	25.00	20.00	2424800	122500	2302300	180606100
TOT	127500	573750000	91683000	348500	317000	126500			191061100	10455000	180606100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	2.08	0.11	1.97
MILLS PER KILOWATT-HOUR	3.00	0.17	2.83
CENTS PER MILLION BTU HEAT INPUT	33.30	1.82	31.48
DOLLARS PER TON OF SULFUR REMOVED	548.24	30.00	518.24
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	78701100	4496500	74204600
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.99	0.11	1.88
MILLS PER KILOWATT-HOUR	2.87	0.17	2.70
CENTS PER MILLION BTU HEAT INPUT	31.88	1.82	30.06
DOLLARS PER TON OF SULFUR REMOVED	525.37	30.01	495.36

Table B-190. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; 4.0 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	204,000	1.5
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fans)	4,253,000	31.4
Stack gas reheat (4 direct oil-fired reheaters)	245,000	1.8
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	594,000	4.4
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,314,000	9.7
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	2,432,000	18.0
Sulfur dioxide reduction unit	2,675,000	19.7
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	204,000	1.5
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	327,000	2.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	650,000	4.8
Construction facilities	645,000	4.8
Subtotal direct investment	13,543,000	100.0
Engineering design and supervision	1,490,000	11.0
Construction field expense	1,490,000	11.0
Contractor fees	677,000	5.0
Contingency	1,354,000	10.0
Subtotal fixed investment	18,554,000	137.0
Allowance for startup and modifications	1,855,000	13.7
Interest during construction (8%/annum rate)	1,484,000	11.0
Total capital investment	21,893,000	161.7

[a] Basis:

Stack gas reheat to 175° by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-191. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; 27,900 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	7,900 tons	52.00/ton	410,800	3.86
Antioxidant	270,600 lb	2.00/lb	541,200	5.08
Catalyst			10,200	0.10
Subtotal raw materials			962,200	9.04
Conversion costs				
Operating labor and supervision	41,000 man-hr	8.00/man-hr	328,000	3.08
Utilities				
Fuel oil (No. 6)	2,719,000 gal	0.23/gal	625,400	5.88
Natural gas	434,800 mcf	1.00/mcf	434,800	4.09
Steam	1,343,900 M lb	1.40/M lb	1,881,500	17.68
Heat credit	53,600 MM Btu	-1.60 /MM Btu	(85,800)	(0.81)
Process water	8,439,000 M gal	0.02/M gal	168,800	1.59
Electricity	39,670,000 kWh	0.018/kWh	714,100	6.71
Maintenance				
Labor and material, .06 x 13,543,000			812,600	7.64
Analyses			94,400	0.89
Subtotal conversion costs			4,973,800	46.75
Subtotal direct costs			5,936,000	55.79
Indirect Costs				
Average capital charges at 14.9% of total capital investment			3,262,100	30.65
Overhead				
Plant, 20% of conversion costs			994,800	9.35
Administrative and marketing			447,600	4.21
Subtotal indirect costs			4,704,500	44.21
Total annual operating cost			10,640,500	100.00

	Dollars/ton product sulfur	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	381.38	2.11	3.04	33.78	347.50

[a] Basis.
Remaining life of power plant, 30 yr.
Coal burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $21,893,000; subtotal direct investment, $13,543,000.
Working capital, $1,048,800.

Table B-192

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 4.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 21893000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12918000	919500	11998500	11998500
2	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12766200	919500	11846700	23845200
3	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12614400	919500	11694900	35540100
4	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12462600	919500	11543100	47083200
5	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12310900	919500	11391400	58474600
6	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12159100	919500	11239600	69714200
7	7000	31500000	5033600	30600	27900	11100	25.00	20.00	12007300	919500	11087800	80802000
8	7000	31500000	5033600	30600	27900	11100	25.00	20.00	11855500	919500	10936000	91738000
9	7000	31500000	5033600	30600	27900	11100	25.00	20.00	11703700	919500	10784200	102522200
10	7000	31500000	5033600	30600	27900	11100	25.00	20.00	11551900	919500	10632400	113154600
11	5000	22500000	3595400	21900	19900	7900	25.00	20.00	9455300	655500	8799800	121954400
12	5000	22500000	3595400	21900	19900	7900	25.00	20.00	9303500	655500	8648000	130602400
13	5000	22500000	3595400	21900	19900	7900	25.00	20.00	9151700	655500	8496200	139098600
14	5000	22500000	3595400	21900	19900	7900	25.00	20.00	8999900	655500	8344400	147443000
15	5000	22500000	3595400	21900	19900	7900	25.00	20.00	8848100	655500	8192600	155635600
16	3500	15750000	2516800	15300	14000	5500	25.00	20.00	7206800	460000	6746800	162382400
17	3500	15750000	2516800	15300	14000	5500	25.00	20.00	7055000	460000	6595000	168977400
18	3500	15750000	2516800	15300	14000	5500	25.00	20.00	6903200	460000	6443200	175420600
19	3500	15750000	2516800	15300	14000	5500	25.00	20.00	6751400	460000	6291400	181712000
20	3500	15750000	2516800	15300	14000	5500	25.00	20.00	6599600	460000	6139600	187851600
21	1500	6750000	1078600	6600	6000	2400	25.00	20.00	4381300	198000	4183300	192034900
22	1500	6750000	1078600	6600	6000	2400	25.00	20.00	4229500	198000	4031500	196066400
23	1500	6750000	1078600	6600	6000	2400	25.00	20.00	4077700	198000	3879700	199946100
24	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3925900	198000	3727900	203674000
25	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3774100	198000	3576100	207250100
26	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3622300	198000	3424300	210674400
27	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3470500	198000	3272500	213946900
28	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3318700	198000	3120700	217067600
29	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3166900	198000	2968900	220036500
30	1500	6750000	1078600	6600	6000	2400	25.00	20.00	3015100	198000	2817100	222853600
TOT	127500	573750000	91683000	558000	508500	202000			239606100	16752500	222853600	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER BARREL OF OIL BURNED									2.61	0.18	2.43	
MILLS PER KILOWATT-HOUR									3.76	0.26	3.50	
CENTS PER MILLION BTU HEAT INPUT									41.76	2.92	38.84	
DOLLARS PER TON OF SULFUR REMOVED									429.40	30.02	399.38	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									99094200	7206300	91887900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER BARREL OF OIL BURNED									2.51	0.18	2.33	
MILLS PER KILOWATT-HOUR									3.61	0.26	3.35	
CENTS PER MILLION BTU HEAT INPUT									40.14	2.92	37.22	
DOLLARS PER TON OF SULFUR REMOVED									413.06	30.03	383.03	

Table B-193. Sodium Solution–SO_2 Reduction Process Summary of Estimated Fixed Investment[a]

(500-MW existing oil-fired power unit. 2.5% S in fuel; 90% SO_2 removal; 2.5 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	170,000	1.2
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between outlet of supplemental fans and stack gas plenum)	5,208,000	35.9
Stack gas reheat (4 direct oil-fired reheaters)	263,000	1.8
Fans (4 fans including ducts and dampers between tie-in to existing duct and inlet to supplemental fans)	1,110,000	7.6
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,071,000	7.4
Sulfur dioxide regeneration (evaporator-crystallizers, packaged boiler, heaters, condensers, strippers, compressers, tanks, agitators, and pumps)	2,129,000	14.7
Sulfur dioxide reduction unit	2,264,000	15.6
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	174,000	1.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system,, and distribution systems for obtaining process water, and electricity from power plant)	690,000	4.8
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	718,000	5.0
Construction facilities	690,000	4.8
Subtotal direct investment	14,487,000	100.0
Engineering design and supervision	1,738,000	12.0
Construction field expense	1,883,000	13.0
Contractor fees	1,014,000	7.0
Contingency	1,594,000	11.0
Subtotal fixed investment	20,716,000	143.0
Allowance for startup and modifications	2,072,000	14.3
Interest during construction (8%/annum rate)	1,657,000	11.4
Total capital investment	24,445,000	168.7

[a] Basis:

Stack gas reheat to 175° by direct oil-fired reheat.

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Minimum in process storage; only pumps are spared.

Remaining life of power unit, 25 yr.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-194. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel,
90% SO_2 removal; 17,820 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	5,100 tons	52.00/ton	265,200	2.58
Antioxidant	172,900 lb	2.00/lb	345,800	3.38
Catalyst			6,500	0.06
Subtotal raw materials			617,500	6.02
Conversion costs				
Operating labor and supervision	38,600 man-hr	8.00/man-hr	308,800	3.01
Utilities				
Fuel oil (No. 6)	10,137,000 gal	0.23/gal	2,331,500	22.72
Natural gas	277,700 mcf	1.00/mcf	277,700	2.71
Heat credit	34,300 MM Btu	-1.60/MM Btu	(54,900)	(0.54)
Process water	5,425,700 M gal	0.02/M gal	108,500	1.06
Electricity	36,560,000 kWh	0.018/kWh	658,100	6.41
Maintenance				
Labor and material, .06 x 14,487,000			869,200	8.47
Analyses			88,000	0.86
Subtotal conversion costs			4,586,900	44.70
Subtotal direct costs			5,204,400	50.72
Indirect Costs				
Average capital charges at 15.3% of total capital investment			3,740,100	36.44
Overhead				
Plant, 20% of conversion costs			917,400	8.94
Administrative and marketing			399,700	3.90
Subtotal indirect costs			5,057,200	49.28
Total annual operating cost			10,261,600	100.00

	Dollars/ton product sulfur	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	575.85	1.99	2.93	31.87	524.62

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 5,145,400 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $24,445,000; subtotal direct investment, $14,487,000.
Working capital, $913,500.

Table B-195

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 500 MW EXISTING OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 24445000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR		NET REVENUE, $/TON		TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
					SULFUR	SODIUM SULFATE	SULFUR	SODIUM SULFATE				
1												
2												
3												
4												
5												
6	7000	32200000	5145400	19600	17800	7100	25.00	20.00	12803900	587000	12216900	12216900
7	7000	32200000	5145400	19600	17800	7100	25.00	20.00	12600500	587000	12013500	24230400
8	7000	32200000	5145400	19600	17800	7100	25.00	20.00	12397100	587000	11810100	36040500
9	7000	32200000	5145400	19600	17800	7100	25.00	20.00	12193700	587000	11606700	47647200
10	7000	32200000	5145400	19600	17800	7100	25.00	20.00	11990300	587000	11403300	59050500
11	5000	23000000	3675300	14000	12700	5100	25.00	20.00	10010000	419500	9590500	68641000
12	5000	23000000	3675300	14000	12700	5100	25.00	20.00	9806700	419500	9387200	78028200
13	5000	23000000	3675300	14000	12700	5100	25.00	20.00	9603300	419500	9183800	87212000
14	5000	23000000	3675300	14000	12700	5100	25.00	20.00	9399900	419500	8980400	96192400
15	5000	23000000	3675300	14000	12700	5100	25.00	20.00	9196500	419500	8777000	104969400
16	3500	16100000	2572700	9800	8900	3500	25.00	20.00	7714000	292500	7421500	112390900
17	3500	16100000	2572700	9800	8900	3500	25.00	20.00	7510700	292500	7218200	119609100
18	3500	16100000	2572700	9800	8900	3500	25.00	20.00	7307300	292500	7014800	126623900
19	3500	16100000	2572700	9800	8900	3500	25.00	20.00	7103900	292500	6811400	133435300
20	3500	16100000	2572700	9800	8900	3500	25.00	20.00	6900500	292500	6608000	140043300
21	1500	6900000	1102600	4200	3800	1500	25.00	20.00	4907700	125000	4782700	144826000
22	1500	6900000	1102600	4200	3800	1500	25.00	20.00	4704300	125000	4579300	149405300
23	1500	6900000	1102600	4200	3800	1500	25.00	20.00	4501000	125000	4376000	153781300
24	1500	6900000	1102600	4200	3800	1500	25.00	20.00	4297600	125000	4172600	157953900
25	1500	6900000	1102600	4200	3800	1500	25.00	20.00	4094200	125000	3969200	161923100
26	1500	6900000	1102600	4200	3800	1500	25.00	20.00	3890800	125000	3765800	165688900
27	1500	6900000	1102600	4200	3800	1500	25.00	20.00	3687400	125000	3562400	169251300
28	1500	6900000	1102600	4200	3800	1500	25.00	20.00	3484000	125000	3359000	172610300
29	1500	6900000	1102600	4200	3800	1500	25.00	20.00	3280700	125000	3155700	175766000
30	1500	6900000	1102600	4200	3800	1500	25.00	20.00	3077300	125000	2952300	178718300
TOT	92500	425500000	67993000	259000	235000	93500			186463300	7745000	178718300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER BARREL OF OIL BURNED									2.74	0.11	2.63	
MILLS PER KILOWATT-HOUR									4.03	0.17	3.86	
CENTS PER MILLION BTU HEAT INPUT									43.82	1.82	42.00	
DOLLARS PER TON OF SULFUR REMOVED									719.94	29.91	690.03	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS									86676700	3824000	82852700	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER BARREL OF OIL BURNED									2.58	0.11	2.47	
MILLS PER KILOWATT-HOUR									3.80	0.17	3.63	
CENTS PER MILLION BTU HEAT INPUT									41.30	1.82	39.48	
DOLLARS PER TON OF SULFUR REMOVED									678.75	29.94	648.81	

Table B-196. Sodium Solution–SO_2 Reduction Process
Summary of Estimated Fixed Investment[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 4.8 tons/hr sulfur)

	Investment, $	Percent of subtotal direct investment
Soda ash and antioxidant receiving, storage, and preparation (pneumatic conveyor and blower, feeders, mixing tank, agitator, and pumps)	229,000	1.3
Sulfur dioxide scrubbers and ducts (4 scrubbers including mist eliminators, pumps, and all ductwork between common feed plenum and inlet of fans)	7,018,000	38.5
Stack gas reheat (4 direct oil-fired reheaters)	431,000	2.4
Fans (4 fans including exhaust gas ducts and dampers between fans and stack gas plenum)	899,000	4.9
Purge treatment (refrigeration system, chiller-crystallizer, feed coolers, centrifuge, rotary dryer, fuel oil combustion facilities, fans, dust collectors, feeders, tanks, agitators, pumps, conveyors, elevator, and bins)	1,480,000	8.1
Sulfur dioxide regeneration (evaporator-crystallizers, heaters, condensers, strippers, compressers, desuperheater, tanks, agitators, and pumps)	2,777,000	15.3
Sulfur dioxide reduction unit	2,970,000	16.3
Sulfur storage (storage and shipping facilities for 30 days production of molten sulfur)	232,000	1.3
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	455,000	2.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	835,000	4.6
Construction facilities	866,000	4.8
Subtotal direct investment	18,192,000	100.0
Engineering design and supervision	1,819,000	10.0
Construction field expense	1,819,000	10.0
Contractor fees	910,000	5.0
Contingency	1,637,000	9.0
Subtotal fixed investment	24,377,000	134.0
Allowance for startup and modifications	2,438,000	13.4
Interest during construction (8%/annum rate)	1,950,000	10.7
Total capital investment	28,765,000	158.1

[a] Basis:
Stack gas reheat to 175° by direct oil-fired reheat.
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Minimum in process storage; only pumps are spared.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-197. Sodium Solution–SO_2 Reduction Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 33,710 tons/yr sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw materials				
Soda ash	9,600 tons	52.00/ton	499,200	3.65
Antioxidant	326,900 lb	2.00/lb	653,800	4.78
Catalyst			12,400	0.09
Subtotal raw materials			1,165,400	8.52
Conversion costs				
Operating labor and supervision	46,500 man-hr	8.00/man-hr	372,000	2.72
Utilities				
Fuel oil (No. 6)	4,881,000 gal	0.23/gal	1,122,600	8.20
Natural gas	525,300 mcf	1.00/mcf	525,300	3.84
Steam	1,623,800 M lb	1.30/M lb	2,110,900	15.42
Heat credit	64,800 MM Btu	-1.60/MM Btu	(103,700)	(0.76)
Process water	10,262,100 M gal	0.02/M gal	205,200	1.50
Electricity	63,820,000 kWh	0.017/kWh	1,084,900	7.93
Maintenance				
Labor and material, .05 x 18,192,000			909,600	6.65
Analyses			156,500	1.14
Subtotal conversion costs			6,383,300	46.64
Subtotal direct costs			7,548,700	55.16
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,286,000	31.31
Overhead				
Plant, 20% of conversion costs			1,276,700	9.33
Administrative and marketing			574,800	4.20
Subtotal indirect costs			6,137,500	44.84
Total annual operating cost			13,686,200	100.00

	Dollars/ton product sulfur	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	406.00	1.41	1.96	22.47	370.00

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 9,731,500 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $28,765,000; subtotal direct investment, $18,192,000.
Working capital, $1,332,600.

Table B-198

SODIUM SOLUTION-SO2 REDUCTION PROCESS, 1000 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO ECON

FIXED INVESTMENT: $ 28765000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SODIUM SULFATE	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	9731500	37000	33700	13400	25.00	20.00	16678700	1110500	15568200	15568200
2	7000	60900000	9731500	37000	33700	13400	25.00	20.00	16479300	1110500	15368800	30937000
3	7000	60900000	9731500	37000	33700	13400	25.00	20.00	16279900	1110500	15169400	46106400
4	7000	60900000	9731500	37000	33700	13400	25.00	20.00	16080400	1110500	14969900	61076300
5	7000	60900000	9731500	37000	33700	13400	25.00	20.00	15881000	1110500	14770500	75846800
6	7000	60900000	9731500	37000	33700	13400	25.00	20.00	15681600	1110500	14571100	90417900
7	7000	60900000	9731500	37000	33700	13400	25.00	20.00	15482100	1110500	14371600	104789500
8	7000	60900000	9731500	37000	33700	13400	25.00	20.00	15282700	1110500	14172200	118961700
9	7000	60900000	9731500	37000	33700	13400	25.00	20.00	15083300	1110500	13972800	132934500
10	7000	60900000	9731500	37000	33700	13400	25.00	20.00	14883800	1110500	13773300	146707800
11	5000	43500000	6951100	26400	24100	9600	25.00	20.00	12038100	794500	11243600	157951400
12	5000	43500000	6951100	26400	24100	9600	25.00	20.00	11838700	794500	11044200	168995600
13	5000	43500000	6951100	26400	24100	9600	25.00	20.00	11639300	794500	10844800	179840400
14	5000	43500000	6951100	26400	24100	9600	25.00	20.00	11439800	794500	10645300	190485700
15	5000	43500000	6951100	26400	24100	9600	25.00	20.00	11240400	794500	10445900	200931600
16	3500	30450000	4865800	18500	16900	6700	25.00	20.00	9173300	556500	8616800	209548400
17	3500	30450000	4865800	18500	16900	6700	25.00	20.00	8973800	556500	8417300	217965700
18	3500	30450000	4865800	18500	16900	6700	25.00	20.00	8774400	556500	8217900	226183600
19	3500	30450000	4865800	18500	16900	6700	25.00	20.00	8575000	556500	8018500	234202100
20	3500	30450000	4865800	18500	16900	6700	25.00	20.00	8375500	556500	7819000	242021100
21	1500	13050000	2085300	7900	7200	2900	25.00	20.00	5594700	238000	5356700	247377800
22	1500	13050000	2085300	7900	7200	2900	25.00	20.00	5395300	238000	5157300	252535100
23	1500	13050000	2085300	7900	7200	2900	25.00	20.00	5195900	238000	4957900	257493000
24	1500	13050000	2085300	7900	7200	2900	25.00	20.00	4996400	238000	4758400	262251400
25	1500	13050000	2085300	7900	7200	2900	25.00	20.00	4797000	238000	4559000	266810400
26	1500	13050000	2085300	7900	7200	2900	25.00	20.00	4597600	238000	4359600	271170000
27	1500	13050000	2085300	7900	7200	2900	25.00	20.00	4398100	238000	4160100	275330100
28	1500	13050000	2085300	7900	7200	2900	25.00	20.00	4198700	238000	3960700	279290800
29	1500	13050000	2085300	7900	7200	2900	25.00	20.00	3999300	238000	3761300	283052100
30	1500	13050000	2085300	7900	7200	2900	25.00	20.00	3799800	238000	3561800	286613900
TOT	127500	1109250000	177252500	673500	614000	244500			306853900	20240000	286613900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.73	0.11	1.62
MILLS PER KILOWATT-HOUR	2.41	0.16	2.25
CENTS PER MILLION BTU HEAT INPUT	27.66	1.82	25.84
DOLLARS PER TON OF SULFUR REMOVED	455.61	30.05	425.56
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	127412800	8707100	118705700
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.67	0.11	1.56
MILLS PER KILOWATT-HOUR	2.32	0.16	2.16
CENTS PER MILLION BTU HEAT INPUT	26.69	1.82	24.87
DOLLARS PER TON OF SULFUR REMOVED	439.51	30.04	409.47

Table B-199. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(200-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 6.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	220,000	2.0
Electrostatic precipitators and inlet ducts (2 high temperature electrostatic precipitators including common feed plenum)	3,765,000	34.0
Sulfur dioxide converters and ducts (2 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	907,000	8.2
Heat recovery and ducts (2 steam/air heaters and 2 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	668,000	6.0
Fans (2 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	625,000	5.6
Sulfuric acid absorber and coolers (1 absorber including mist eliminator, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	3,736,000	33.7
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	222,000	2.0
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	41,000	0.4
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	369,000	3.3
Construction facilities	528,000	4.8
Subtotal direct investment	11,081,000	100.0
Engineering design and supervision	1,441,000	13.0
Construction field expense	1,441,000	13.0
Contractor fees	776,000	7.0
Contingency	1,219,000	11.0
Subtotal fixed investment	15,958,000	144.0
Allowance for startup and modifications	1,596,000	14.4
Interest during construction (8%/annum rate)	1,277,000	11.5
Total capital investment excluding catalyst	18,831,000	169.9
Catalyst	706,000	6.4
Total capital investment	19,537,000	176.3

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-200. Catalytic Oxidation Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(200-MW new, coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 44,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	42,800 liters	1.65/liters	70,600	1.67
Subtotal raw material			70,600	1.67
Conversion costs				
Operating labor and supervision	6,000 man-hr	8.00/man-hr	48,000	1.13
Utilities				
Steam	73,000 M lb	0.80/M lb	58,400	1.38
Heat credit	403,600 MM Btu	-0.60/MM Btu	(242,200)	(5.72)
Process water	128,000 M gal	0.08/M gal	10,200	0.24
Electricity	36,980,000 kWh	0.011/kWh	406,800	9.61
Maintenance				
Labor and material, .05 x 11,081,000			554,100	13.09
Analyses			25,800	0.61
Subtotal conversion costs			861,100	20.34
Subtotal direct costs			931,700	22.01
Indirect Costs				
Average capital charges at 14.9% of total capital investment			2,911,000	68.77
Overhead				
Plant, 20% of conversion costs			172,200	4.07
Administrative and marketing			217,800	5.15
Subtotal indirect costs			3,301,000	77.99
Total annual operating cost			4,232,700	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	94.27	7.89	3.02	32.86	288.53

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $19,537,000; subtotal direct investment, $11,081,000.
Working capital, $182,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-201

CATALYTIC OXIDATION PROCESS, 200 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 19537000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	536700	14700	44900	6.00	6265100	269400	5995700	5995700
2	7000	12880000	536700	14700	44900	6.00	6129600	269400	5860200	11855900
3	7000	12880000	536700	14700	44900	6.00	5994200	269400	5724800	17580700
4	7000	12880000	536700	14700	44900	6.00	5858700	269400	5589300	23170000
5	7000	12880000	536700	14700	44900	6.00	5723300	269400	5453900	28623900
6	7000	12880000	536700	14700	44900	6.00	5587800	269400	5318400	33942300
7	7000	12880000	536700	14700	44900	6.00	5452400	269400	5183000	39125300
8	7000	12880000	536700	14700	44900	6.00	5316900	269400	5047500	44172800
9	7000	12880000	536700	14700	44900	6.00	5181500	269400	4912100	49084900
10	7000	12880000	536700	14700	44900	6.00	5046000	269400	4776600	53861500
11	5000	9200000	383300	10500	32100	6.00	4625100	192600	4432500	58294000
12	5000	9200000	383300	10500	32100	6.00	4489700	192600	4297100	62591100
13	5000	9200000	383300	10500	32100	6.00	4354200	192600	4161600	66752700
14	5000	9200000	383300	10500	32100	6.00	4218800	192600	4026200	70778900
15	5000	9200000	383300	10500	32100	6.00	4083300	192600	3890700	74669600
16	3500	6440000	268300	7300	22400	6.00	3715600	134400	3581200	78250800
17	3500	6440000	268300	7300	22400	6.00	3580100	134400	3445700	81696500
18	3500	6440000	268300	7300	22400	6.00	3444700	134400	3310300	85006800
19	3500	6440000	268300	7300	22400	6.00	3309200	134400	3174800	88181600
20	3500	6440000	268300	7300	22400	6.00	3173800	134400	3039400	91221000
21	1500	2760000	115000	3100	9600	6.00	2682000	57600	2624400	93845400
22	1500	2760000	115000	3100	9600	6.00	2546600	57600	2489000	96334400
23	1500	2760000	115000	3100	9600	6.00	2411100	57600	2353500	98687900
24	1500	2760000	115000	3100	9600	6.00	2275700	57600	2218100	100906000
25	1500	2760000	115000	3100	9600	6.00	2140200	57600	2082600	102988600
26	1500	2760000	115000	3100	9600	6.00	2004800	57600	1947200	104935800
27	1500	2760000	115000	3100	9600	6.00	1869300	57600	1811700	106747500
28	1500	2760000	115000	3100	9600	6.00	1733900	57600	1676300	108423800
29	1500	2760000	115000	3100	9600	6.00	1598400	57600	1540800	109964600
30	1500	2760000	115000	3100	9600	6.00	1463000	57600	1405600	111370000
TOT	127500	234600000	9775000	267000	817500		116275000	4905000	111370000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							11.90	0.51	11.39	
MILLS PER KILOWATT-HOUR							4.56	0.19	4.37	
CENTS PER MILLION BTU HEAT INPUT							49.56	2.09	47.47	
DOLLARS PER TON OF SULFUR REMOVED							435.49	18.37	417.12	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							46934900	2111400	44823500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							11.16	0.50	10.66	
MILLS PER KILOWATT-HOUR							4.28	0.20	4.08	
CENTS PER MILLION BTU HEAT INPUT							46.49	2.09	44.40	
DOLLARS PER TON OF SULFUR REMOVED							407.77	18.34	389.43	

Table B-202. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(200-MW existing coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; 6.6 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Startup bypass ducts and dampers	137,000	1.4
Electrostatic precipitators and inlet ducts (2 low temperature electrostatic precipitators including common feed plenum)	1,849,000	19.3
Sulfur dioxide converters and ducts (2 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	847,000	8.8
Reheat (4 direct oil-fired reheaters and 2 flue gas heat exchangers)	1,395,000	14.5
Fans (2 fans including exhaust gas ducts between fans and stack gas plenum)	952,000	9.8
Sulfuric acid absorber and coolers (1 absorber including mist eliminator, coolers, tanks, pumps, and ducts and dampers between absorber and fans)	2,890,000	30.2
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	264,000	2.7
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	377,000	3.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	439,000	4.6
Construction facilities	458,000	4.8
Subtotal direct investment	9,608,000	100.0
Engineering design and supervision	1,345,000	14.0
Construction field expense	1,441,000	15.0
Contractor fees	865,000	9.0
Contingency	1,153,000	12.0
Subtotal fixed investment	14,412,000	150.0
Allowance for startup and modifications	1,441,000	15.0
Interest during construction (8%/annum rate)	1,153,000	12.0
Total capital investment excluding catalyst	17,006,000	177.0
Catalyst	729,000	7.6
Total capital investment	17,735,000	184.6

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-197
Only pumps are spared.
Remaining life of power unit, 20 yr.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-203. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW existing, coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 46,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	44,200 liters	1.65/liters	72,900	1.24
Subtotal raw material			72,900	1.24
Conversion costs				
Operating labor and supervision	6,000 man-hr	8.00/man-hr	48,000	0.82
Utilities				
Fuel oil (No. 2)	4,270,000 gal	0.30/gal	1,281,000	21.90
Process water	3,288,000 M gal	0.03/M gal	98,600	1.69
Electricity	30,830,000 kWh	0.011/kWh	339,100	5.80
Maintenance				
Labor and material, .05 x 9,608,000			480,400	8.21
Analyses			25,800	0.44
Subtotal conversion costs			2,272,900	38.86
Subtotal direct costs			2,345,800	40.10
Indirect Costs				
Average capital charges at 15.9% of total capital investment			2,819,900	48.21
Overhead				
Plant, 20% of conversion costs			454,600	7.77
Administrative and marketing			229,100	3.92
Subtotal indirect costs			3,503,600	59.90
Total annual operating cost			5,849,400	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	126.06	10.55	4.18	43.98	386.10

[a] Basis:
Remaining life of power plant, 20 yr.
Coal burned, 554,200 tons/yr, 9,500 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $17,735,000; subtotal direct investment, $9,608,000.
Working capital, $412,000.
Investment and operating cost for disposal of fly ash excluded.

Table B-204

CATALYTIC OXIDATION PROCESS, 200 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 17735000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10							6901000	198600	6702400	6702400
11	5000	9500000	395800	10800	33100	6.00	6716500	198600	6517900	13220300
12	5000	9500000	395800	10800	33100	6.00	6532100	198600	6333500	19553800
13	5000	9500000	395800	10800	33100	6.00	6347600	198600	6149000	25702800
14	5000	9500000	395800	10800	33100	6.00	6163200	198600	5964600	31667400
15	5000	9500000	395800	10800	33100	6.00	5369600	139200	5230400	36897800
16	3500	6650000	277100	7600	23200	6.00	5185200	139200	5046000	41943800
17	3500	6650000	277100	7600	23200	6.00	5000700	139200	4861500	46805300
18	3500	6650000	277100	7600	23200	6.00	4816200	139200	4677000	51482300
19	3500	6650000	277100	7600	23200	6.00	4631800	139200	4492600	55974900
20	3500	6650000	277100	7600	23200	6.00	3598400	59400	3539000	59513900
21	1500	2850000	118700	3200	9900	6.00	3414000	59400	3354600	62868500
22	1500	2850000	118700	3200	9900	6.00	3229500	59400	3170100	66038600
23	1500	2850000	118700	3200	9900	6.00	3045100	59400	2985700	69024300
24	1500	2850000	118700	3200	9900	6.00	2860600	59400	2801200	71825500
25	1500	2850000	118700	3200	9900	6.00	2676200	59400	2616800	74442300
26	1500	2850000	118700	3200	9900	6.00	2491700	59400	2432300	76874600
27	1500	2850000	118700	3200	9900	6.00	2307300	59400	2247900	79122500
28	1500	2850000	116700	3200	9900	6.00	2122800	59400	2063400	81185900
29	1500	2850000	118700	3200	9900	6.00	1938300	59400	1878900	83064800
30	1500	2850000	118700	3200	9900	6.00				
TOT	57500	109250000	4551500	124000	380500		85347800	2283000	83064800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	18.75	0.50	18.25
MILLS PER KILOWATT-HOUR	7.42	0.20	7.22
CENTS PER MILLION BTU HEAT INPUT	78.12	2.09	76.03
DOLLARS PER TON OF SULFUR REMOVED	688.29	18.41	669.88
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	43644200	1221200	42423000
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	17.93	0.50	17.43
MILLS PER KILOWATT-HOUR	7.10	0.20	6.90
CENTS PER MILLION BTU HEAT INPUT	74.71	2.09	72.62
DOLLARS PER TON OF SULFUR REMOVED	657.29	18.39	638.90

Table B-205. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 16.0 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Startup bypass ducts and dampers	304,000	1.4
Electrostatic precipitators and inlet ducts (4 low temperature electrostatic precipitators including common feed plenum)	4,260,000	19.8
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	1,983,000	9.3
Reheat (8 direct oil-fired reheaters and 4 flue gas heat exchangers)	3,258,000	15.2
Fans (4 fans including exhaust gas ducts between fans and stack gas plenum)	2,133,000	10.0
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between absorbers and fans)	6,840,000	31.9
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	481,000	2.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	527,000	2.5
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	613,000	2.9
Construction facilities	1,020,000	4.8
Subtotal direct investment	21,419,000	100.0
Engineering design and supervision	2,570,000	12.0
Construction field expense	2,784,000	13.0
Contractor fees	1,499,000	7.0
Contingency	2,356,000	11.0
Subtotal fixed investment	30,628,000	143.0
Allowance for startup and modifications	3,063,000	14.3
Interest during construction (8%/annum rate)	2,450,000	11.4
Total capital investment excluding catalyst	36,141,000	168.7
Catalyst	1,766,000	8.3
Total capital investment	37,907,000	177.0

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-206. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW existing, coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 112,300 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	107,000 liters	1.65/liters	176,600	1.42
Subtotal raw material			176,600	1.42
Conversion costs				
Operating labor and supervision	7,890 man-hr	8.00/man-hr	63,100	0.51
Utilities				
Fuel oil (No. 2)	10,330,000 gal	0.30/gal	3,099,000	24.99
Process water	7,961,000 M gal	0.02/M gal	159,200	1.28
Electricity	74,600,000 kWh	0.010/kWh	746,000	6.02
Maintenance				
Labor and material, .04 x 21,419,000			856,800	6.91
Analyses			48,000	0.39
Subtotal conversion costs			4,972,100	40.10
Subtotal direct costs			5,148,700	41.52
Indirect Costs				
Average capital charges at 15.3% of total capital investment			5,799,800	46.78
Overhead				
Plant, 20% of conversion costs			994,400	8.02
Administrative and marketing			456,700	3.68
Subtotal indirect costs			7,250,900	58.48
Total annual operating cost			12,399,600	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	110.41	9.24	3.54	38.51	338.05

[a]Basis:

Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $37,907,000; subtotal direct investment, $21,419,000.
Working capital, $898,600.
Investment and operating cost for disposal of fly ash excluded.

Table B-207

CATALYTIC OXIDATION PROCESS, 500 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 37907000

YEARS AFTER POWER UNIT START	ANNUAL OPERA- TION, KW-HR/ KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36700	112300	6.00	16342000	673800	15668200	15668200
7	7000	32200000	1341700	36700	112300	6.00	16026600	673800	15352800	31021000
8	7000	32200000	1341700	36700	112300	6.00	15711200	673800	15037400	46058400
9	7000	32200000	1341700	36700	112300	6.00	15395800	673800	14722000	60780400
10	7000	32200000	1341700	36700	112300	6.00	15080400	673800	14406600	75187000
11	5000	23000000	956300	26200	80200	6.00	13003900	481200	12522700	87709700
12	5000	23000000	958300	26200	80200	6.00	12688500	481200	12207300	99917000
13	5000	23000000	958300	26200	80200	6.00	12373100	481200	11891900	111808900
14	5000	23000000	956300	26200	80200	6.00	12057700	481200	11576500	123385400
15	5000	23000000	958300	26200	80200	6.00	11742300	481200	11261100	134646500
16	3500	16100000	670800	18300	56200	6.00	10081900	337200	9744700	144391200
17	3500	16100000	670800	18300	56200	6.00	9766500	337200	9429300	153820500
18	3500	16100000	670800	18300	56200	6.00	9451100	337200	9113900	162934400
19	3500	16100000	670800	18300	56200	6.00	9135700	337200	8798500	171732900
20	3500	16100000	670800	18300	56200	6.00	8820300	337200	8483100	180216000
21	1500	6900000	287500	7900	24100	6.00	6647900	144600	6503300	186719300
22	1500	6900000	287500	7900	24100	6.00	6332500	144600	6187900	192907200
23	1500	6900000	287500	7900	24100	6.00	6017100	144600	5872500	198779700
24	1500	6900000	287500	7900	24100	6.00	5701700	144600	5557100	204336800
25	1500	6900000	287500	7900	24100	6.00	5386300	144600	5241700	209578500
26	1500	6900000	287500	7900	24100	6.00	5070900	144600	4926300	214504800
27	1500	6900000	287500	7900	24100	6.00	4755600	144600	4611000	219115800
28	1500	6900000	287500	7900	24100	6.00	4440200	144600	4295600	223411400
29	1500	6900000	287500	7900	24100	6.00	4124800	144600	3980200	227391600
30	1500	6900000	287500	7900	24100	6.00	3809400	144600	3664800	231056400
TOT	92500	425500000	17729000	485000	1484500		239963400	8907000	231056400	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	13.54	0.51	13.03
MILLS PER KILOWATT-HOUR	5.19	0.19	5.00
CENTS PER MILLION BTU HEAT INPUT	56.40	2.10	54.30
DOLLARS PER TON OF SULFUR REMOVED	494.77	18.37	476.40
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	111000100	4392300	106607800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	12.69	0.50	12.19
MILLS PER KILOWATT-HOUR	4.67	0.20	4.67
CENTS PER MILLION BTU HEAT INPUT	52.89	2.10	50.79
DOLLARS PER TON OF SULFUR REMOVED	464.24	18.37	445.87

Table B-208. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal, 9.0 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	491,000	1.9
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	8,736,000	34.6
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	2,145,000	8.5
Heat recovery and ducts (4 steam/air heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	1,475,000	5.8
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,412,000	5.6
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	8,917,000	35.4
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	279,000	1.1
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	57,000	0.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	518,000	2.1
Construction facilities	1,202,000	4.8
Subtotal direct investment	25,232,000	100.0
Engineering design and supervision	2,776,000	11.0
Construction field expense	2,776,000	11.0
Contractor fees	1,262,000	5.0
Contingency	2,523,000	10.0
Subtotal fixed investment	34,569,000	137.0
Allowance for startup and modifications	3,457,000	13.7
Interest during construction (8%/annum rate)	2,766,000	11.0
Total capital investment excluding catalyst	40,792,000	161.7
Catalyst	1,728,000	6.8
Total capital investment	42,520,000	168.5

[a] Basis:

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-209. Catalytic Oxidation Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW new, coal-fired power unit, 2.0% S in fuel; 90% SO_2 removal; 62,800 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	104,700 liters	1.65/liters	172,800	1.97
Subtotal raw material			172,800	1.97
Conversion costs				
Operating labor and supervision	7,380 man-hr	8.00/man-hr	59,000	0.67
Utilities				
Steam	179,000 M lb	0.70/M lb	125,300	1.42
Heat credit	813,000 MM Btu	-0.60/MM Btu	(487,800)	(5.54)
Process water	178,000 M gal	0.08/M gal	14,200	0.16
Electricity	87,870,000 kWh	0.010/kWh	878,700	9.98
Maintenance				
Labor and material, .04 x 25,232,000			1,009,300	11.47
Analyses			32,400	0.37
Subtotal conversion costs			1,631,100	18.53
Subtotal direct costs			1,803,900	20.50
Indirect Costs				
Average capital charges at 14.9% of total capital investment			6,335,500	71.98
Overhead				
Plant, 20% of conversion costs			326,200	3.71
Administrative and marketing			335,600	3.81
Subtotal indirect costs			6,997,300	79.50
Total annual operating cost			8,801,200	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	140.15	6.71	2.51	27.94	429.33

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $42,520,000; subtotal direct investment, $25,232,000.
Working capital, $341,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-210

CATALYTIC OXIDATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 2.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 42520000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	20500	62800	6.00	13224700	376800	12847900	12847900
2	7000	31500000	1312500	20500	62800	6.00	12929900	376800	12553100	25401000
3	7000	31500000	1312500	20500	62800	6.00	12635100	376800	12258300	37659300
4	7000	31500000	1312500	20500	62800	6.00	12340300	376800	11963500	49622800
5	7000	31500000	1312500	20500	62800	6.00	12045500	376800	11668700	61291500
6	7000	31500000	1312500	20500	62800	6.00	11750700	376800	11373900	72665400
7	7000	31500000	1312500	20500	62800	6.00	11455900	376800	11079100	83744500
8	7000	31500000	1312500	20500	62800	6.00	11161100	376800	10784300	94528800
9	7000	31500000	1312500	20500	62800	6.00	10866300	376800	10489500	105018300
10	7000	31500000	1312500	20500	62800	6.00	10571500	376800	10194700	115213000
11	5000	22500000	937500	14600	44900	6.00	9729100	269400	9459700	124672700
12	5000	22500000	937500	14600	44900	6.00	9434300	269400	9164900	133837600
13	5000	22500000	937500	14600	44900	6.00	9139500	269400	8870100	142707700
14	5000	22500000	937500	14600	44900	6.00	8844700	269400	8575300	151283000
15	5000	22500000	937500	14600	44900	6.00	8549900	269400	8280500	159563500
16	3500	15750000	656200	10300	31400	6.00	7813800	188400	7625400	167188900
17	3500	15750000	656200	10300	31400	6.00	7519000	188400	7330600	174519500
18	3500	15750000	656200	10300	31400	6.00	7224200	188400	7035800	181555300
19	3500	15750000	656200	10300	31400	6.00	6929400	188400	6741000	188296300
20	3500	15750000	656200	10300	31400	6.00	6634600	188400	6446200	194742500
21	1500	6750000	281200	4400	13500	6.00	5671100	81000	5590100	200332600
22	1500	6750000	281200	4400	13500	6.00	5376300	81000	5295300	205627900
23	1500	6750000	281200	4400	13500	6.00	5081500	81000	5000500	210628400
24	1500	6750000	281200	4400	13500	6.00	4786700	81000	4705700	215334100
25	1500	6750000	281200	4400	13500	6.00	4491900	81000	4410900	219745000
26	1500	6750000	281200	4400	13500	6.00	4197100	81000	4116100	223861100
27	1500	6750000	281200	4400	13500	6.00	3902300	81000	3821300	227682400
28	1500	6750000	281200	4400	13500	6.00	3607500	81000	3526500	231208900
29	1500	6750000	281200	4400	13500	6.00	3312700	81000	3231700	234440600
30	1500	6750000	281200	4400	13500	6.00	3017900	81000	2936900	237377500
TOT	127500	573750000	23905500	373500	1144500		244244500	6867000	237377500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.22	0.29	9.93	
MILLS PER KILOWATT-HOUR							3.83	0.11	3.72	
CENTS PER MILLION BTU HEAT INPUT							42.57	1.20	41.37	
DOLLARS PER TON OF SULFUR REMOVED							653.93	18.38	635.55	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							98734200	2953900	95780300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.60	0.29	9.31	
MILLS PER KILOWATT-HOUR							3.60	0.11	3.49	
CENTS PER MILLION BTU HEAT INPUT							39.99	1.20	38.79	
DOLLARS PER TON OF SULFUR REMOVED							614.40	18.38	596.02	

Table B-211. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 15.7 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	491,000	1.9
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	8,736,000	34.4
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	2,145,000	8.5
Heat recovery and ducts (4 steam/air heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	1,475,000	5.8
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,412,000	5.6
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	8,917,000	35.2
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	409,000	1.6
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	57,000	0.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	518,000	2.0
Construction facilities	1,208,000	4.8
Subtotal direct investment	25,368,000	100.0
Engineering design and supervision	2,790,000	11.0
Construction field expense	2,790,000	11.0
Contractor fees	1,268,000	5.0
Contingency	2,537,000	10.0
Subtotal fixed investment	34,753,000	137.0
Allowance for startup and modifications	3,475,000	13.7
Interest during construction (8%/annum rate)	2,780,000	11.0
Total capital investment excluding catalyst	41,008,000	161.7
Catalyst	1,728,000	6.8
Total capital investment	42,736,000	168.5

[a] Basis:

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-212. Catalytic Oxidation Process Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new, coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 109,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	104,700 liters	1.65/liters	172,800	1.95
Subtotal raw material			172,800	1.95
Conversion costs				
Operating labor and supervision	7,890 man-hr	8.00/man-hr	63,100	0.71
Utilities				
Steam	179,000 M lb	0.70/M lb	125,300	1.41
Heat credit	987,000 MM Btu	-0.60/MM Btu	(592,200)	(6.67)
Process water	312,000 M gal	0.08/M gal	25,000	0.28
Electricity	90,440,000 kWh	0.010/kWh	904,400	10.19
Maintenance				
Labor and material, .04 × 25,368,000			1,014,700	11.44
Analyses			48,000	0.54
Subtotal conversion costs			1,588,300	17.90
Subtotal direct costs			1,761,100	19.85
Indirect Costs				
Average capital charges at 14.9% of total capital investment			6,367,700	71.75
Overhead				
Plant, 20% of conversion costs			317,700	3.58
Administrative and marketing			427,400	4.82
Subtotal indirect costs			7,112,800	80.15
Total annual operating cost			8,873,900	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	80.75	6.76	2.54	28.17	247.32

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $42,736,000; subtotal direct investment, $25,368,000.
Working capital, $347,300.
Investment and operating cost for disposal of fly ash excluded.

Table B-213

CATALYTIC OXIDATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 42736000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	35900	109900	6.00	13319800	659400	12660400	12660400
2	7000	31500000	1312500	35900	109900	6.00	13023500	659400	12364100	25024500
3	7000	31500000	1312500	35900	109900	6.00	12727200	659400	12067800	37092300
4	7000	31500000	1312500	35900	109900	6.00	12430900	659400	11771500	48863800
5	7000	31500000	1312500	35900	109900	6.00	12134600	659400	11475200	60339000
6	7000	31500000	1312500	35900	109900	6.00	11838300	659400	11178900	71517900
7	7000	31500000	1312500	35900	109900	6.00	11542000	659400	10882600	82400500
8	7000	31500000	1312500	35900	109900	6.00	11245700	659400	10586300	92986800
9	7000	31500000	1312500	35900	109900	6.00	10949400	659400	10290000	103276800
10	7000	31500000	1312500	35900	109900	6.00	10653100	659400	9993700	113270500
11	5000	22500000	937500	25600	78500	6.00	9806100	471000	9335100	122605600
12	5000	22500000	937500	25600	78500	6.00	9509800	471000	9038800	131644400
13	5000	22500000	937500	25600	78500	6.00	9213500	471000	8742500	140386900
14	5000	22500000	937500	25600	78500	6.00	8917200	471000	8446200	148833100
15	5000	22500000	937500	25600	78500	6.00	8620900	471000	8149900	156983000
16	3500	15750000	656200	17900	55000	6.00	7879700	330000	7549700	164532700
17	3500	15750000	656200	17900	55000	6.00	7583500	330000	7253500	171786200
18	3500	15750000	656200	17900	55000	6.00	7287200	330000	6957200	178743400
19	3500	15750000	656200	17900	55000	6.00	6990900	330000	6660900	185404300
20	3500	15750000	656200	17900	55000	6.00	6694600	330000	6364600	191768900
21	1500	6750000	281200	7700	23600	6.00	5720000	141600	5578400	197347300
22	1500	6750000	281200	7700	23600	6.00	5423700	141600	5282100	202629400
23	1500	6750000	281200	7700	23600	6.00	5127400	141600	4985800	207615200
24	1500	6750000	281200	7700	23600	6.00	4831100	141600	4689500	212304700
25	1500	6750000	281200	7700	23600	6.00	4534800	141600	4393200	216697900
26	1500	6750000	281200	7700	23600	6.00	4238500	141600	4096900	220794800
27	1500	6750000	281200	7700	23600	6.00	3942200	141600	3800600	224595400
28	1500	6750000	281200	7700	23600	6.00	3645900	141600	3504300	228099700
29	1500	6750000	281200	7700	23600	6.00	3349600	141600	3208000	231307700
30	1500	6750000	281200	7700	23600	6.00	3053300	141600	2911700	234219600
TOT	127500	573750000	23905500	653500	2002500		246234400	12015000	234219400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.30	0.50	9.80	
MILLS PER KILOWATT-HOUR							3.86	0.19	3.67	
CENTS PER MILLION BTU HEAT INPUT							42.92	2.10	40.82	
DOLLARS PER TON OF SULFUR REMOVED							376.79	18.38	358.41	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							99489800	5168900	94320900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.67	0.50	9.17	
MILLS PER KILOWATT-HOUR							3.63	0.19	3.44	
CENTS PER MILLION BTU HEAT INPUT							40.30	2.10	38.20	
DOLLARS PER TON OF SULFUR REMOVED							353.68	18.38	335.30	

Table B-214. Catalytic Oxidation Process Summary of Estimated Fixed Investment[a]

(500-MW new coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; 22.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	491,000	1.9
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	8,736,000	34.3
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	2,145,000	8.4
Heat recovery and ducts (4 steam/air heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	1,475,000	5.8
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,412,000	5.5
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	8,917,000	35.1
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	521,000	2.0
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	57,000	0.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	518,000	2.0
Construction facilities	1,214,000	4.8
Subtotal direct investment	25,486,000	100.0
Engineering design and supervision	2,803,000	11.0
Construction field expense	2,803,000	11.0
Contractor fees	1,274,000	5.0
Contingency	2,549,000	10.0
Subtotal fixed investment	34,915,000	137.0
Allowance for startup and modifications	3,492,000	13.7
Interest during construction (8%/annum rate)	2,793,000	11.0
Total capital investment excluding catalyst	41,200,000	161.7
Catalyst	1,728,000	6.8
Total capital investment	42,928,000	168.5

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-215. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new, coal-fired power unit, 5.0% S in fuel; 90% SO_2 removal; 157,000 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	104,700 liters	1.65/liters	172,800	1.94
Subtotal raw material			172,800	1.94
Conversion costs				
Operating labor and supervision	8,990 man-hr	8.00/man-hr	71,900	0.80
Utilities				
Steam	179,000 M lb	0.70/M lb	125,300	1.40
Heat credit	1,161,000 MM Btu	-0.60/MM Btu	(696,600)	(7.79)
Process water	445,000 M gal	0.08/M gal	35,600	0.40
Electricity	93,010,000 kWh	0.010/kWh	930,100	10.40
Maintenance				
Labor and material, .04 x 25,486,000			1,019,400	11.40
Analyses			61,600	0.69
Subtotal conversion costs			1,547,300	17.30
Subtotal direct costs			1,720,100	19.24
Indirect Costs				
Average capital charges at 14.9% of total capital investment			6,396,300	71.54
Overhead				
Plant, 20% of conversion costs			309,500	3.46
Administrative and marketing			514,600	5.76
Subtotal indirect costs			7,220,400	80.76
Total annual operating cost			8,940,500	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	56.95	6.81	2.55	28.38	174.41

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $42,928,000; subtotal direct investment, $25,486,000.
Working capital, $352,500.
Investment and operating cost for disposal of fly ash excluded.

Table B-216

CATALYTIC OXIDATION PROCESS, 500 MW NEW COAL FIRED POWER UNIT, 5.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 42928000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1312500	51300	157000	6.00	13406500	942000	12464500	12464500
2	7000	31500000	1312500	51300	157000	6.00	13108900	942000	12166900	24631400
3	7000	31500000	1312500	51300	157000	6.00	12811300	942000	11869300	36500700
4	7000	31500000	1312500	51300	157000	6.00	12513600	942000	11571600	48072300
5	7000	31500000	1312500	51300	157000	6.00	12216000	942000	11274000	59346300
6	7000	31500000	1312500	51300	157000	6.00	11918400	942000	10976400	70322700
7	7000	31500000	1312500	51300	157000	6.00	11620800	942000	10678800	81001500
8	7000	31500000	1312500	51300	157000	6.00	11323100	942000	10381100	91382600
9	7000	31500000	1312500	51300	157000	6.00	11025500	942000	10083500	101466100
10	7000	31500000	1312500	51300	157000	6.00	10727900	942000	9785900	111252000
11	5000	22500000	937500	36600	112100	6.00	9878500	672600	9205900	120457900
12	5000	22500000	937500	36600	112100	6.00	9580800	672600	8908200	129366100
13	5000	22500000	937500	36600	112100	6.00	9283200	672600	8610600	137976700
14	5000	22500000	937500	36600	112100	6.00	8985600	672600	8313000	146289700
15	5000	22500000	937500	36600	112100	6.00	8687900	672600	8015300	154305000
16	3500	15750000	656200	25600	78500	6.00	7942600	471000	7471600	161776600
17	3500	15750000	656200	25600	78500	6.00	7645000	471000	7174000	168950600
18	3500	15750000	656200	25600	78500	6.00	7347400	471000	6876400	175827000
19	3500	15750000	656200	25600	78500	6.00	7049700	471000	6578700	182405700
20	3500	15750000	656200	25600	78500	6.00	6752100	471000	6281100	188686800
21	1500	6750000	281200	11000	33600	6.00	5767400	201600	5565800	194252600
22	1500	6750000	281200	11000	33600	6.00	5469800	201600	5268200	199520800
23	1500	6750000	281200	11000	33600	6.00	5172100	201600	4970500	204491300
24	1500	6750000	281200	11000	33600	6.00	4874500	201600	4672900	209164200
25	1500	6750000	281200	11000	33600	6.00	4576900	201600	4375300	213539500
26	1500	6750000	281200	11000	33600	6.00	4279200	201600	4077600	217617100
27	1500	6750000	281200	11000	33600	6.00	3981600	201600	3780000	221397100
28	1500	6750000	281200	11000	33600	6.00	3684000	201600	3482400	224879500
29	1500	6750000	281200	11000	33600	6.00	3386400	201600	3184800	228064300
30	1500	6750000	281200	11000	33600	6.00	3088700	201600	2887100	230951600
TOT	127500	573750000	23905500	934000	2859000		248105400	17154000	230951400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.38	0.72	9.66	
MILLS PER KILOWATT-HOUR							3.89	0.27	3.62	
CENTS PER MILLION BTU HEAT INPUT							43.24	2.99	40.25	
DOLLARS PER TON OF SULFUR REMOVED							265.64	18.37	247.27	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							100188100	7382800	92805300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.74	0.72	9.02	
MILLS PER KILOWATT-HOUR							3.65	0.27	3.38	
CENTS PER MILLION BTU HEAT INPUT							40.58	2.99	37.59	
DOLLARS PER TON OF SULFUR REMOVED							249.22	18.36	230.86	

Table B-217. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 31.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Startup bypass ducts and dampers	439,000	1.2
Electrostatic precipitators and inlet ducts (4 low temperature electrostatic precipitators including common feed plenum)	7,002,000	19.5
Sulfur dioxide converters and ducts (8 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	3,464,000	9.6
Reheat (16 direct oil-fired reheaters and 8 flue gas heat exchangers)	5,610,000	15.6
Fans (4 fans including exhaust gas ducts between fans and stack gas plenum)	3,193,000	8.9
Sulfuric acid absorbers and coolers (4 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between absorbers and fans)	12,340,000	34.2
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	759,000	2.1
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	680,000	1.9
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	791,000	2.2
Construction facilities	1,714,000	4.8
Subtotal direct investment	35,992,000	100.0
Engineering design and supervision	3,959,000	11.0
Construction field expense	4,319,000	12.0
Contractor fees	2,519,000	7.0
Contingency	3,599,000	10.0
Subtotal fixed investment	50,388,000	140.0
Allowance for startup and modifications	5,039,000	14.0
Interest during construction (8%/annum rate)	4,031,000	11.2
Total capital investment excluding catalyst	59,458,000	165.2
Catalyst	3,455,000	9.6
Total capital investment	62,913,000	174.8

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-218. Catalytic Oxidation Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW existing coal-fired power unit, 3.5% S in fuel;
90% SO_2 removal; 219,800 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	209,400 liters	1.65/liters	345,500	1.61
Subtotal raw material			345,500	1.61
Conversion costs				
Operating labor and supervision	10,380 man-hr	8.00/man-hr	83,000	0.39
Utilities				
Fuel oil (No. 2)	20,220,000 gal	0.30/gal	6,066,000	28.27
Process water	15,576,000 M gal	0.02/M gal	311,500	1.45
Electricity	145,970,000 kWh	0.009/kWh	1,313,700	6.12
Maintenance				
Labor and material, .03 x 35,992,000			1,079,800	5.03
Analyses			77,200	0.36
Subtotal conversion costs			8,931,200	41.62
Subtotal direct costs			9,276,700	43.23
Indirect Costs				
Average capital charges at 15.3% of total capital investment			9,625,700	44.85
Overhead				
Plant, 20% of conversion costs			1,786,200	8.32
Administrative and marketing			772,200	3.60
Subtotal indirect costs			12,184,100	56.77
Total annual operating cost			21,460,800	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	97.64	8.18	3.07	34.06	299.06

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 2,625,000 tons/yr, 9,000 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $62,913,000; subtotal direct investment, $35,992,000.
Working capital, $1,613,100.
Investment and operating cost for disposal of fly ash excluded.

Table B-219

CATALYTIC OXIDATION PROCESS, 1000 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 62913000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	2625000	71800	219800	6.00	28003700	1318800	26684900	26684900
7	7000	63000000	2625000	71800	219800	6.00	27480300	1318800	26161500	52846400
8	7000	63000000	2625000	71800	219800	6.00	26956800	1318800	25638000	78484400
9	7000	63000000	2625000	71800	219800	6.00	26433400	1318800	25114600	103599000
10	7000	63000000	2625000	71800	219800	6.00	25910000	1318800	26591200	128190200
11	5000	45000000	1875000	51300	157000	6.00	22162100	942000	21220100	149410300
12	5000	45000000	1875000	51300	157000	6.00	21638700	942000	20696700	170107000
13	5000	45000000	1875000	51300	157000	6.00	21115300	942000	20173300	190280300
14	5000	45000000	1875000	51300	157000	6.00	20591800	942000	19649800	209930100
15	5000	45000000	1875000	51300	157000	6.00	20068600	942000	19126600	229056500
16	3500	31500000	1312500	35900	109900	6.00	17096100	659400	16436700	245493200
17	3500	31500000	1312500	35900	109900	6.00	16572700	659400	15913300	261406500
18	3500	31500000	1312500	35900	109900	6.00	16049200	659400	15389800	276796300
19	3500	31500000	1312500	35900	109900	6.00	15525800	659400	14866400	291662700
20	3500	31500000	1312500	35900	109900	6.00	15002400	659400	16363000	306005700
21	1500	13500000	562500	15400	47100	6.00	11133300	282600	10850700	316856400
22	1500	13500000	562500	15400	47100	6.00	10609900	282600	10327300	327183700
23	1500	13500000	562500	15400	47100	6.00	10086500	282600	9803900	336987600
24	1500	13500000	562500	15400	47100	6.00	9563000	282600	9280400	346268000
25	1500	13500000	562500	15400	47100	6.00	9039600	282600	8757000	355025000
26	1500	13500000	562500	15400	47100	6.00	8516200	282600	8233600	363258600
27	1500	13500000	562500	15400	47100	6.00	7992700	282600	7710100	370968700
28	1500	13500000	562500	15400	47100	6.00	7469300	282600	7186700	378155400
29	1500	13500000	562500	15400	47100	6.00	6945900	282600	6663300	384818700
30	1500	13500000	562500	15400	47100	6.00	6422600	282600	6139800	390958500
TOT	92500	832500000	34687500	949000	2904500		408385500	17427000	390958500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							11.77	0.50	11.27	
MILLS PER KILOWATT-HOUR							4.41	0.18	4.23	
CENTS PER MILLION BTU HEAT INPUT							49.06	2.10	46.96	
DOLLARS PER TON OF SULFUR REMOVED							430.33	18.36	411.97	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							189608600	8595900	181012700	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							11.08	0.50	10.58	
MILLS PER KILOWATT-HOUR							4.16	0.19	3.97	
CENTS PER MILLION BTU HEAT INPUT							46.17	2.09	44.08	
DOLLARS PER TON OF SULFUR REMOVED							405.15	18.37	386.78	

Table B-220. Catalytic Oxidation Process Summary of Estimated Fixed Investment[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 30.3 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	706,000	1.7
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	14,231,000	33.8
Sulfur dioxide converters and ducts (8 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	3,707,000	8.8
Heat recovery and ducts (4 steam/air heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	2,037,000	4.8
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	2,097,000	5.0
Sulfuric acid absorbers and coolers (4 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	15,925,000	37.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	640,000	1.5
Utilities (instrument air generation and supply system, and distribution systems for obtaining process steam, water, and electricity from power plant)	74,000	0.2
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	666,000	1.6
Construction facilities	2,004,000	4.8
Subtotal direct investment	42,087,000	100.0
Engineering design and supervision	4,209,000	10.0
Construction field expense	4,209,000	10.0
Contractor fees	2,104,000	5.0
Contingency	3,788,000	9.0
Subtotal fixed investment	56,397,000	134.0
Allowance for startup and modifications	5,640,000	13.4
Interest during construction (8%/annum rate)	4,512,000	10.7
Total capital investment excluding catalyst	66,549,000	158.1
Catalyst	3,340,000	8.1
Total capital investment	69,889,000	166.1

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-221. Catalytic Oxidation Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(1,000-MW new coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 212,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	202,400 liters	1.65/liters	334,000	2.39
Subtotal raw material			334,000	2.39
Conversion costs				
Operating labor and supervision	10,380 man-hr	8.00/man-hr	83,000	0.59
Utilities				
Steam	346,000 M lb	0.60/M lb	207,600	1.49
Heat credit	1,908,200 MM Btu	-0.60/MM Btu	(1,144,900)	(8.20)
Process water	603,000 M gal	0.07/M gal	42,200	0.30
Electricity	174,840,000 kWh	0.009/kWh	1,573,600	11.28
Maintenance				
Labor and material, .03 x 42,087,000			1,262,600	9.05
Analyses			77,200	0.55
Subtotal conversion costs			2,101,300	15.06
Subtotal direct costs			2,435,300	17.45
Indirect Costs				
Average capital charges at 14.9% of total capital investment			10,413,500	74.61
Overhead				
Plant, 20% of conversion costs			420,300	3.01
Administrative and marketing			688,500	4.93
Subtotal indirect costs			11,522,300	82.55
Total annual operating cost			13,957,600	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	65.71	5.50	1.99	22.92	201.21

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $69,889,000; subtotal direct investment, $42,087,000.
Working capital, $496,400.
Investment and operating cost for disposal of fly ash excluded.

Table B-222

CATALYTIC OXIDATION PROCESS, 1000 MW NEW COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 69889000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2537500	69400	212400	6.00	21228300	1274400	19953900	19953900
2	7000	60900000	2537500	69400	212400	6.00	20743800	1274400	19469400	39423300
3	7000	60900000	2537500	69400	212400	6.00	20259200	1274400	18984800	58408100
4	7000	60900000	2537500	69400	212400	6.00	19774600	1274400	18500200	76908300
5	7000	60900000	2537500	69400	212400	6.00	19290100	1274400	18015700	94924000
6	7000	60900000	2537500	69400	212400	6.00	18805500	1274400	17531100	112455100
7	7000	60900000	2537500	69400	212400	6.00	18321000	1274400	17046600	129501700
8	7000	60900000	2537500	69400	212400	6.00	17836400	1274400	16562000	146063700
9	7000	60900000	2537500	69400	212400	6.00	17351900	1274400	16077500	162141200
10	7000	60900000	2537500	69400	212400	6.00	16867300	1274400	15592900	177734100
11	5000	43500000	1812500	49600	151700	6.00	15585200	910200	14675000	192409100
12	5000	43500000	1812500	49600	151700	6.00	15100700	910200	14190500	206599600
13	5000	43500000	1812500	49600	151700	6.00	14616100	910200	13705900	220305500
14	5000	43500000	1812500	49600	151700	6.00	14131600	910200	13221400	233526900
15	5000	43500000	1812500	49600	151700	6.00	13647000	910200	12736800	246263700
16	3500	30450000	1268700	34700	106200	6.00	12522300	637200	11885100	258148800
17	3500	30450000	1268700	34700	106200	6.00	12037700	637200	11400500	269549300
18	3500	30450000	1266700	34700	106200	6.00	11553100	637200	10915900	280465200
19	3500	30450000	1268700	34700	106200	6.00	11068600	637200	10431400	290896600
20	3500	30450000	1268700	34700	106200	6.00	10584000	637200	9946800	300843400
21	1500	13050000	543700	14900	45500	6.00	9136100	273000	8863100	309706500
22	1500	13050000	543700	14900	45500	6.00	8651500	273000	8378500	318085000
23	1500	13050000	543700	14900	45500	6.00	8167000	273000	7894000	325979000
24	1500	13050000	543700	14900	45500	6.00	7682400	273000	7409400	333388400
25	1500	13050000	543700	14900	45500	6.00	7197800	273000	6924800	340313200
26	1500	13050000	543700	14900	45500	6.00	6713300	273000	6440300	346753500
27	1500	13050000	543700	14900	45500	6.00	6228700	273000	5955700	352709200
28	1500	13050000	543700	14900	45500	6.00	5744200	273000	5471200	358180400
29	1500	13050000	543700	14900	45500	6.00	5259600	273000	4986600	363167000
30	1500	13050000	543700	14900	45500	6.00	4775100	273000	4502100	367669100
TOT	127500	1109250000	46218000	1264500	3868500		390880100	23211000	367669100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF CCAL BURNED	8.46	0.50	7.96
MILLS PER KILOWATT-HCUR	3.07	0.19	2.88
CENTS PER MILLION BTU HEAT INPUT	35.24	2.09	33.15
DOLLARS PER TON OF SULFUR REMOVED	309.12	18.36	290.76
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	158106100	9988500	148117600
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF CCAL BURNED	7.95	0.50	7.45
MILLS PER KILOWATT-HCUR	2.88	0.18	2.70
CENTS PER MILLION BTU HEAT INPUT	33.12	2.09	31.03
DOLLARS PER TON OF SULFUR REMOVED	290.64	18.37	272.28

Table B-223. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 16.0 tons/hr 100% H_2SO_4 without existing particulate collection facilities)

	Investment, $	Percent of subtotal direct investment
Startup bypass ducts and dampers	304,000	1.2
Electrostatic precipitators and inlet ducts (4 low temperature electrostatic precipitators including common feed plenum)	7,594,000	30.4
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	1,983,000	8.0
Reheat (8 direct oil-fired reheaters and 4 flue gas heat exchangers)	3,258,000	13.1
Fans (4 fans including exhaust gas ducts between fans and stack gas plenum)	2,133,000	8.6
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between absorbers and fans)	6,840,000	27.4
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	481,000	1.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	527,000	2.1
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	613,000	2.5
Construction facilities	1,187,000	4.8
Subtotal direct investment	24,920,000	100.0
Engineering design and supervision	2,990,000	12.0
Construction field expense	3,240,000	13.0
Contractor fees	1,744,000	7.0
Contingency	2,741,000	11.0
Subtotal fixed investment	35,635,000	143.0
Allowance for startup and modifications	3,564,000	14.3
Interest during construction (8%/annum rate)	2,851,000	11.4
Total capital investment excluding catalyst	42,050,000	168.7
Catalyst	1,766,000	7.1
Total capital investment	43,816,000	175.8

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-224. Catalytic Oxidation Process
Total Average Annual Operating Costs–Regulated Utility Economics[a]

(500-MW existing coal-fired power unit, 3.5% S in fuel; 90% SO_2 removal; 112,300 tons/yr 100% H_2SO_4 without existing particulate collection [illegible]es)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	107,000 liters	1.65/liters	176,600	1.30
Subtotal raw material			176,600	1.30
Conversion costs				
Operating labor and supervision	7,890 man-hr	8.00/man-hr	63,100	0.46
Utilities				
Fuel oil (No. 2)	10,330,000 gal	0.30/gal	3,099,000	22.79
Process water	7,961,000 M gal	0.02/M gal	159,200	1.17
Electricity	80,470,000 kWh	0.010/kWh	804,700	5.92
Maintenance				
Labor and material, .04 × 24,920,000			996,800	7.33
Analyses			48,000	0.35
Subtotal conversion costs			5,170,800	38.02
Subtotal direct costs			5,347,400	39.32
Indirect Costs				
Average capital charges at 15.3% of total capital investment			6,703,800	49.30
Overhead				
Plant, 20% of conversion costs			1,034,200	7.61
Administrative and marketing			512,900	3.77
Subtotal indirect costs			8,250,900	60.68
Total annual operating cost			13,598,300	100.00

	Dollars/ton 100% H_2SO_4	Dollars/ton coal burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	121.09	10.14	3.89	42.23	370.73

[a] Basis:
Remaining life of power plant, 25 yr.
Coal burned, 1,341,700 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $43,816,000; subtotal direct investment, $24,920,000.
Working capital, $938,300.
Investment and operating cost for disposal of fly ash excluded.

Table B-225

CATALYTIC OXIDATION PROCESS, 500 MW EXISTING COAL FIRED POWER UNIT, 3.5% S IN FUEL, 90% SO2 REMOVAL, WITHOUT EXISTING ESP

FIXED INVESTMENT: $ 43816000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1341700	36700	112300	6.00	18155100	673800	17481300	17481300
7	7000	32200000	1341700	36700	112300	6.00	17790600	673800	17116800	34598100
8	7000	32200000	1341700	36700	112300	6.00	17426000	673800	16752200	51350300
9	7000	32200000	1341700	36700	112300	6.00	17061500	673800	16387700	67738000
10	7000	32200000	1341700	36700	112300	6.00	16697000	673800	16023200	83761200
11	5000	23000000	958300	26200	80200	6.00	14506500	481200	14025300	97786500
12	5000	23000000	958300	26200	80200	6.00	14142000	481200	13660800	111447300
13	5000	23000000	958300	26200	80200	6.00	13777400	481200	13296200	124743500
14	5000	23000000	958300	26200	80200	6.00	13412900	481200	12931700	137675200
15	5000	23000000	958300	26200	80200	6.00	13048600	481200	12567400	150242600
16	3500	16100000	670800	18300	56200	6.00	11286400	337200	10949200	161191600
17	3500	16100000	670800	18300	56200	6.00	10921900	337200	10584700	171776300
18	3500	16100000	670800	18300	56200	6.00	10557300	337200	10220100	181996400
19	3500	16100000	670800	18300	56200	6.00	10192800	337200	9855600	191852000
20	3500	16100000	670800	18300	56200	6.00	9828300	337200	9491100	201343100
21	1500	6900000	287500	7900	24100	6.00	7526600	144600	7382000	208725100
22	1500	6900000	287500	7900	24100	6.00	7162100	144600	7017500	215742600
23	1500	6900000	287500	7900	24100	6.00	6797500	144600	6652900	222395500
24	1500	6900000	287500	7900	24100	6.00	6433000	144600	6288400	228683900
25	1500	6900000	287500	7900	24100	6.00	6068500	144600	5923900	234607800
26	1500	6900000	287500	7900	24100	6.00	5703900	144600	5559300	240167100
27	1500	6900000	287500	7900	24100	6.00	5339400	144600	5194800	245361900
28	1500	6900000	287500	7900	24100	6.00	4974800	144600	4830200	250192100
29	1500	6900000	287500	7900	24100	6.00	4610300	144600	4465700	254657800
30	1500	6900000	287500	7900	24100	6.00	4245700	144600	4101100	258758900
TOT	92500	425500000	17729000	485000	1484500		267665900	8907000	258758900	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							15.10	0.50	14.60	
MILLS PER KILOWATT-HOUR							5.79	0.20	5.59	
CENTS PER MILLION BTU HEAT INPUT							62.91	2.10	60.81	
DOLLARS PER TON OF SULFUR REMOVED							551.89	18.37	533.52	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							123517200	4392400	119124800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							14.12	0.50	13.62	
MILLS PER KILOWATT-HOUR							5.41	0.19	5.22	
CENTS PER MILLION BTU HEAT INPUT							58.85	2.09	56.76	
DOLLARS PER TON OF SULFUR REMOVED							516.59	16.37	498.22	

Table B-226. Catalytic Oxidation Process Summary of Estimated Fixed Investment[a]

(200-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 3.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	200,000	2.7
Electrostatic precipitators and inlet ducts (2 high temperature electrostatic precipitators including common feed plenum)	890,000	12.1
Sulfur dioxide converters and ducts (2 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	787,000	10.7
Heat recovery and ducts (2 direct oil-fired heaters and 2 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	688,000	9.4
Fans (2 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	554,000	7.5
Sulfuric acid absorber and coolers (1 absorber including mist eliminator, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	3,210,000	43.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	145,000	2.0
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	150,000	2.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	367,000	5.0
Construction facilities	350,000	4.8
Subtotal direct investment	7,341,000	100.0
Engineering design and supervision	954,000	13.0
Construction field expense	954,000	13.0
Contractor fees	514,000	7.0
Contingency	808,000	11.0
Subtotal fixed investment	10,571,000	144.0
Allowance for startup and modifications	1,057,000	14.4
Interest during construction (8%/annum rate)	846,000	11.5
Total capital investment excluding catalyst	12,474,000	169.9
Catalyst	595,000	8.1
Total capital investment	13,069,000	178.0

[a] Basis:

Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.

Only pumps are spared.

Investment requirements for disposal of fly ash excluded.

Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-227. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(200-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 24,000 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	36,100 liters	1.65/liters	59,600	2.17
Subtotal raw material			59,600	2.17
Conversion costs				
Operating labor and supervision	5,810 man-hr	8.00/man-hr	46,500	1.69
Utilities				
Fuel oil (No. 6)	437,000 gal	0.23/gal	100,500	3.65
Heat credit	288,700 MM Btu	-1.60/MM Btu	(461,900)	(16.79)
Process water	68,000 M gal	0.08/M gal	5,400	0.20
Electricity	21,900,000 kWh	0.019/kWh	416,100	15.13
Maintenance				
Labor and material, .05 x 7,341,000			367,100	13.35
Analyses			16,600	0.60
Subtotal conversion costs			490,300	17.83
Subtotal direct costs			549,900	20.00
Indirect Costs				
Average capital charges at 14.9% of total capital investment			1,947,300	70.80
Overhead				
Plant, 20% of conversion costs			98,100	3.57
Administrative and marketing			154,800	5.63
Subtotal indirect costs			2,200,200	80.00
Total annual operating cost			2,750,100	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	114.59	1.34	1.96	21.35	351.23

[a] Basis:

Remaining life of power plant, 30 yr.
Oil burned, 2,058,200 bbl/yr, 9,200 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $13,069,000; subtotal direct investment, $7,341,000.
Working capital, $111,500.
Investment and operating cost for disposal of fly ash excluded.

Table B-228

CATALYTIC OXIDATION PROCESS, 200 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 13069000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	2058200	7800	24000	6.00	4109700	144000	3965700	3965700
2	7000	12880000	2058200	7800	24000	6.00	4019000	144000	3875000	7840700
3	7000	12880000	2058200	7800	24000	6.00	3928400	144000	3784400	11625100
4	7000	12880000	2058200	7800	24000	6.00	3837800	144000	3693800	15318900
5	7000	12880000	2058200	7800	24000	6.00	3747200	144000	3603200	18922100
6	7000	12880000	2058200	7800	24000	6.00	3656600	144000	3512600	22434700
7	7000	12880000	2058200	7800	24000	6.00	3566000	144000	3422000	25856700
8	7000	12880000	2058200	7800	24000	6.00	3475400	144000	3331400	29188100
9	7000	12880000	2058200	7800	24000	6.00	3384800	144000	3240800	32428900
10	7000	12880000	2058200	7800	24000	6.00	3294200	144000	3150200	35579100
11	5000	9200000	1470100	5600	17100	6.00	3040600	102600	2938000	38517100
12	5000	9200000	1470100	5600	17100	6.00	2950000	102600	2847400	41364500
13	5000	9200000	1470100	5600	17100	6.00	2859400	102600	2756800	44121300
14	5000	9200000	1470100	5600	17100	6.00	2768800	102600	2666200	46787500
15	5000	9200000	1470100	5600	17100	6.00	2678200	102600	2575600	49363100
16	3500	6440000	1029100	3900	12000	6.00	2452800	72000	2380800	51743900
17	3500	6440000	1029100	3900	12000	6.00	2362200	72000	2290200	54034100
18	3500	6440000	1029100	3900	12000	6.00	2271600	72000	2199600	56233700
19	3500	6440000	1029100	3900	12000	6.00	2181000	72000	2109000	58342700
20	3500	6440000	1029100	3900	12000	6.00	2090400	72000	2018400	60361100
21	1500	2760000	441000	1700	5100	6.00	1785900	30600	1755300	62116400
22	1500	2760000	441000	1700	5100	6.00	1695300	30600	1664700	63781100
23	1500	2760000	441000	1700	5100	6.00	1604600	30600	1574000	65355100
24	1500	2760000	441000	1700	5100	6.00	1514000	30600	1483400	66838500
25	1500	2760000	441000	1700	5100	6.00	1423400	30600	1392800	68231300
26	1500	2760000	441000	1700	5100	6.00	1332800	30600	1302200	69533500
27	1500	2760000	441000	1700	5100	6.00	1242200	30600	1211600	70745100
28	1500	2760000	441000	1700	5100	6.00	1151600	30600	1121000	71866100
29	1500	2760000	441000	1700	5100	6.00	1061000	30600	1030400	72896500
30	1500	2760000	441000	1700	5100	6.00	970400	30600	939800	73836300
TOT	127500	234600000	37488000	142500	436500		76455300	2619000	73836300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							2.04	0.07	1.97	
MILLS PER KILOWATT-HOUR							3.00	0.10	2.90	
CENTS PER MILLION BTU HEAT INPUT							32.59	1.12	31.47	
DOLLARS PER TON OF SULFUR REMOVED							536.53	18.38	518.15	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							30781900	1128100	29653800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.91	0.07	1.84	
MILLS PER KILOWATT-HOUR							2.81	0.11	2.70	
CENTS PER MILLION BTU HEAT INPUT							30.49	1.12	29.37	
DOLLARS PER TON OF SULFUR REMOVED							502.97	18.43	484.54	

Table B-229. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 1.0% S in fuel;
90% SO_2 removal; 3.3 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	447,000	2.7
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	2,069,000	12.6
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	1,860,000	11.3
Heat recovery and ducts (4 direct oil-fired heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	1,517,000	9.2
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,249,000	7.6
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	7,668,000	46.5
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	143,000	0.9
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	210,000	1.3
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	515.000	3.1
Construction facilities	784,000	4.8
Subtotal direct investment	16,462,000	100.0
Engineering design and supervision	1,811,000	11.0
Construction field expense	1,811,000	11.0
Contractor fees	823,000	5.0
Contingency	1,646,000	10.0
Subtotal fixed investment	22,553,000	137.0
Allowance for startup and modifications	2,255,000	13.7
Interest during construction (8%/annum rate)	1,804,000	11.0
Total capital investment excluding catalyst	26,612,000	161.7
Catalyst	1,455,000	8.8
Total capital investment	28,067,000	170.5

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-230. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 1.0% S in fuel; 90% SO_2 removal; 23,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	88,200 liters	1.65/liters	145,500	2.53
Subtotal raw material			145,500	2.53
Conversion costs				
Operating labor and supervision	7,190 man-hr	8.00/man-hr	57,500	1.00
Utilities				
Fuel oil (No. 6)	1,068,000 gal	0.23/gal	245,600	4.28
Heat credit	576,000 MM Btu	-1.60/MM Btu	(921,600)	(16.04)
Process water	67,000 M gal	0.08/M gal	5,400	0.09
Electricity	51,630,000 kWh	0.018/kWh	929,300	16.18
Maintenance				
Labor and material, .04 x 16,462,000			658,500	11.47
Analyses			16,300	0.28
Subtotal conversion costs			991,000	17.26
Subtotal direct costs			1,136,500	19.79
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,182,000	72.81
Overhead				
Plant, 20% of conversion costs			198,200	3.45
Administrative and marketing			226,900	3.95
Subtotal indirect costs			4,607,100	80.21
Total annual operating cost			5,743,600	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	245.45	1.14	1.64	18.23	750.80

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $28,067,000; subtotal direct investment, $16,462,000.
Working capital, $218,600.
Investment and operating cost for disposal of fly ash excluded.

Table B-231

CATALYTIC OXIDATION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 1.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 28067000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	7700	23400	6.00	8663500	140400	8523100	8523100
2	7000	31500000	5033600	7700	23400	6.00	8468900	140400	8328500	16851600
3	7000	31500000	5033600	7700	23400	6.00	8274300	140400	8133900	24985500
4	7000	31500000	5033600	7700	23400	6.00	8079700	140400	7939300	32924800
5	7000	31500000	5033600	7700	23400	6.00	7885100	140400	7744700	40669500
6	7000	31500000	5033600	7700	23400	6.00	7690500	140400	7550100	48219600
7	7000	31500000	5033600	7700	23400	6.00	7495900	140400	7355500	55575100
8	7000	31500000	5033600	7700	23400	6.00	7301300	140400	7160900	62736000
9	7000	31500000	5033600	7700	23400	6.00	7106700	140400	6966300	69702300
10	7000	31500000	5033600	7700	23400	6.00	6912100	140400	6771700	76474000
11	5000	22500000	3595400	5500	16700	6.00	6379000	100200	6278800	82752800
12	5000	22500000	3595400	5500	16700	6.00	6184400	100200	6084200	88837000
13	5000	22500000	3595400	5500	16700	6.00	5989800	100200	5889600	94726600
14	5000	22500000	3595400	5500	16700	6.00	5795200	100200	5695000	100421600
15	5000	22500000	3595400	5500	16700	6.00	5600600	100200	5500400	105922000
16	3500	15750000	2516800	3800	11700	6.00	5131200	70200	5061000	110983000
17	3500	15750000	2516800	3800	11700	6.00	4936600	70200	4866400	115849400
18	3500	15750000	2516800	3800	11700	6.00	4742000	70200	4671800	120521200
19	3500	15750000	2516800	3800	11700	6.00	4547300	70200	4477100	124998300
20	3500	15750000	2516800	3800	11700	6.00	4352700	70200	4282500	129280800
21	1500	6750000	1078600	1600	5000	6.00	3736400	30000	3706400	132987200
22	1500	6750000	1078600	1600	5000	6.00	3541800	30000	3511800	136499000
23	1500	6750000	1078600	1600	5000	6.00	3347200	30000	3317200	139816200
24	1500	6750000	1078600	1600	5000	6.00	3152600	30000	3122600	142938800
25	1500	6750000	1078600	1600	5000	6.00	2958000	30000	2928000	145866800
26	1500	6750000	1078600	1600	5000	6.00	2763400	30000	2733400	148600200
27	1500	6750000	1078600	1600	5000	6.00	2568800	30000	2538800	151139000
28	1500	6750000	1078600	1600	5000	6.00	2374200	30000	2344200	153483200
29	1500	6750000	1078600	1600	5000	6.00	2179600	30000	2149600	155632800
30	1500	6750000	1078600	1600	5000	6.00	1985000	30000	1955000	157587800
TOT	127500	57375000	91683000	139500	426000		160143800	2556000	157587800	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.75	0.03	1.72	
MILLS PER KILOWATT-HOUR							2.51	0.04	2.47	
CENTS PER MILLION BTU HEAT INPUT							27.91	0.44	27.47	
DOLLARS PER TON OF SULFUR REMOVED							1147.98	18.32	1129.66	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							64674200	1100200	63574000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.64	0.03	1.61	
MILLS PER KILOWATT-HOUR							2.36	0.04	2.32	
CENTS PER MILLION BTU HEAT INPUT							26.19	0.44	25.75	
DOLLARS PER TON OF SULFUR REMOVED							1074.32	18.27	1056.05	

Table B-232. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 8.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	447,000	2.7
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	2,069,000	12.5
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	1,860,000	11.2
Heat recovery and ducts (4 direct oil-fired heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	1,517,000	9.1
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,249,000	7.5
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	7,668,000	46.2
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	267,000	1.6
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	210,000	1.3
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	515,000	3.1
Construction facilities	790,000	4.8
Subtotal direct investment	16,592,000	100.0
Engineering design and supervision	1,825,000	11.0
Construction field expense	1,825,000	11.0
Contractor fees	830,000	5.0
Contingency	1,659,000	10.0
Subtotal fixed investment	22,731,000	137.0
Allowance for startup and modifications	2,273,000	13.7
Interest during construction (8%/annum rate)	1,818,000	11.0
Total capital investment excluding catalyst	26,822,000	161.7
Catalyst	1,445,000	8.7
Total capital investment	28,277,000	170.4

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-233. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 58,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	88,200 liters	1.65/liters	145,500	2.56
Subtotal raw material			145,500	2.56
Conversion costs				
Operating labor and supervision	7,380 man-hr	8.00/man-hr	59,000	1.04
Utilities				
Fuel oil (No. 6)	1,068,000 gal	0.23/gal	245,600	4.33
Heat credit	705,900 MM Btu	-1.60/MM Btu	(1,129,400)	(19.90)
Process water	166,000 M gal	0.08/M gal	13,300	0.23
Electricity	53,550,000 kWh	0.018/kWh	963,900	16.98
Maintenance				
Labor and material, .04 x 16,592,000			663,700	11.69
Analyses			31,000	0.55
Subtotal conversion costs			847,100	14.92
Subtotal direct costs			992,600	17.48
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,213,300	74.22
Overhead				
Plant, 20% of conversion costs			169,400	2.98
Administrative and marketing			302,200	5.32
Subtotal indirect costs			4,684,900	82.52
Total annual operating cost			5,677,500	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	96.89	1.13	1.62	18.02	296.79

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $28,277,000; subtotal direct investment, $16,592,000.
Working capital, $205,500.
Investment and operating cost for disposal of fly ash excluded.

Table B-234

CATALYTIC OXIDATION PROCESS, 500 MW NEW CIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 28277000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	19100	58600	6.00	8619200	351600	8267600	8267600
2	7000	31500000	5033600	19100	58600	6.00	8423200	351600	8071600	16339200
3	7000	31500000	5033600	19100	56600	6.00	8227100	351600	7875500	24214700
4	7000	31500000	5033600	19100	58600	6.00	8031000	351600	7679400	31894100
5	7000	31500000	5033600	19100	58600	6.00	7835000	351600	7483400	39377500
6	7000	31500000	5033600	19100	58600	6.00	7638900	351600	7287300	46664800
7	7000	31500000	5033600	19100	58600	6.00	7442900	351600	7091300	53756100
8	7000	31500000	5033600	19100	58600	6.00	7246800	351600	6895200	60651300
9	7000	31500000	5033600	19100	58600	6.00	7050700	351600	6699100	67350400
10	7000	31500000	5033600	19100	58600	6.00	6854700	351600	6503100	73853500
11	5000	22500000	3595400	13700	41900	6.00	6358800	251400	6107400	79960900
12	5000	22500000	3595400	13700	41900	6.00	6162700	251400	5911300	85872200
13	5000	22500000	3595400	13700	41900	6.00	5966700	251400	5715300	91587500
14	5000	22500000	3595400	13700	41900	6.00	5770600	251400	5519200	97106700
15	5000	22500000	3595400	13700	41900	6.00	5574600	251400	5323200	102429900
16	3500	15750000	2516800	9600	29300	6.00	5130400	175800	4954600	107384500
17	3500	15750000	2516800	9600	29300	6.00	4934300	175800	4758500	112143000
18	3500	15750000	2516800	9600	29300	6.00	4738300	175800	4562500	116705500
19	3500	15750000	2516800	9600	29300	6.00	4542200	175800	4366400	121071900
20	3500	15750000	2516800	9600	29300	6.00	4346200	175800	4170400	125242300
21	1500	6750000	1078600	4100	12600	6.00	3759000	75600	3683400	128925700
22	1500	6750000	1078600	4100	12600	6.00	3562900	75600	3487300	132413000
23	1500	6750000	1078600	4100	12600	6.00	3366900	75600	3291300	135704300
24	1500	6750000	1078600	4100	12600	6.00	3170800	75600	3095200	138799500
25	1500	6750000	1078600	4100	12600	6.00	2974800	75600	2899200	141698700
26	1500	6750000	1078600	4100	12600	6.00	2778700	75600	2703100	144401800
27	1500	6750000	1078600	4100	12600	6.00	2582600	75600	2507000	146908800
28	1500	6750000	1078600	4100	12600	6.00	2386600	75600	2311000	149219800
29	1500	6750000	1078600	4100	12600	6.00	2190500	75600	2114900	151334700
30	1500	6750000	1078600	4100	12600	6.00	1994500	75600	1918900	153253600
TOT	127500	573750000	91683000	348500	1068000		159661600	6408000	153253600	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER BARREL OF OIL BURNED	1.74	C.07	1.67
MILLS PER KILOWATT-HCUR	2.50	0.10	2.40
CENTS PER MILLION BTU HEAT INPUT	27.83	1.12	26.71
DOLLARS PER TON OF SULFUR REMOVED	458.14	18.39	439.75
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS	64347900	2756400	61591500
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER BARREL OF OIL BURNED	1.63	0.07	1.56
MILLS PER KILOWATT-HCUR	2.35	0.10	2.25
CENTS PER MILLION BTU HEAT INPUT	26.06	1.11	24.95
DOLLARS PER TON OF SULFUR REMOVED	429.56	18.40	411.16

Table B-235. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW new oil-fired power unit, 4.0% S in fuel; 90% SO_2 removal; 13.4 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	447,000	2.7
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	2,069,000	12.4
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	1,860,000	11.1
Heat recovery and ducts (4 direct oil-fired heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	1,517,000	9.1
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,249,000	7.5
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	7,668,000	45.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	367,000	2.2
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	210,000	1.3
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	515,000	3.1
Construction facilities	795,000	4.8
Subtotal direct investment	16,697,000	100.0
Engineering design and supervision	1,837,000	11.0
Construction field expense	1,837,000	11.0
Contractor fees	835,000	5.0
Contingency	1,670,000	10.0
Subtotal fixed investment	22,876,000	137.0
Allowance for startup and modifications	2,288,000	13.7
Interest during construction (8%/annum rate)	1,830,000	11.0
Total capital investment excluding catalyst	26,994,000	161.7
Catalyst	1,455,000	8.7
Total capital investment	28,449,000	170.4

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-236. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW new oil-fired power unit, 4.0% S in fuel;
90% SO_2 removal; 93,800 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	88,200 liters	1.65/liters	145,500	2.62
Subtotal raw material			145,500	2.62
Conversion costs				
Operating labor and supervision	7,890 man-hr	8.00/man-hr	63,100	1.13
Utilities				
Fuel oil (No. 6)	1,068,000 gal	0.23/gal	245,600	4.41
Heat credit	853,800 MM Btu	-1.60/MM Btu	(1,366,100)	(24.54)
Process water	266,000 M gal	0.08/M gal	21,300	0.38
Electricity	55,460,000 kWh	0.018/kWh	998,300	17.94
Maintenance				
Labor and material, .04 × 16,697,000			667,900	12.00
Analyses			43,000	0.77
Subtotal conversion costs			673,100	12.09
Subtotal direct costs			818,600	14.71
Indirect Costs				
Average capital charges at 14.9% of total capital investment			4,238,900	76.17
Overhead				
Plant, 20% of conversion costs			134,600	2.42
Administrative and marketing			373,000	6.70
Subtotal indirect costs			4,746,500	85.29
Total annual operating cost			5,565,100	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	59.33	1.11	1.59	17.67	181.75

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 5,033,600 bbl/yr, 9,000 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $28,449,000; subtotal direct investment, $16,697,000.
Working capital, $186,900.
Investment and operating cost for disposal of fly ash excluded.

Table B-237

CATALYTIC OXIDATION PROCESS, 500 MW NEW OIL FIRED POWER UNIT, 4.0% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 28449000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/ KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	5033600	30600	93800	6.00	8524800	562800	7962000	7962000
2	7000	31500000	5033600	30600	93800	6.00	8327500	562800	7764700	15726700
3	7000	31500000	5033600	30600	93800	6.00	8130300	562800	7567500	23294200
4	7000	31500000	5033600	30600	93800	6.00	7933100	562800	7370300	30664500
5	7000	31500000	5033600	30600	93800	6.00	7735800	562800	7173000	37837500
6	7000	31500000	5033600	30600	93800	6.00	7538600	562800	6975800	44813300
7	7000	31500000	5033600	30600	93800	6.00	7341300	562800	6778500	51591800
8	7000	31500000	5033600	30600	93800	6.00	7144100	562800	6581300	58173100
9	7000	31500000	5033600	30600	93800	6.00	6946800	562800	6384000	64557100
10	7000	31500000	5033600	30600	93800	6.00	6749600	562800	6186800	70743900
11	5000	22500000	3595400	21900	67000	6.00	6308600	402000	5906600	76650500
12	5000	22500000	3595400	21900	67000	6.00	6111400	402000	5709400	82359900
13	5000	22500000	3595400	21900	67000	6.00	5914100	402000	5512100	87872000
14	5000	22500000	3595400	21900	67000	6.00	5716900	402000	5314900	93186900
15	5000	22500000	3595400	21900	67000	6.00	5519600	402000	5117600	98304500
16	3500	15750000	2516800	15300	46900	6.00	5112900	281400	4831500	103136000
17	3500	15750000	2516800	15300	46900	6.00	4915600	281400	4634200	107770200
18	3500	15750000	2516800	15300	46900	6.00	4718400	281400	4437000	112207200
19	3500	15750000	2516800	15300	46900	6.00	4521200	281400	4239800	116447000
20	3500	15750000	2516800	15300	46900	6.00	4323900	281400	4042500	120489500
21	1500	6750000	1078600	6600	20100	6.00	3779300	120600	3658700	124148200
22	1500	6750000	1078600	6600	20100	6.00	3582000	120600	3461400	127609600
23	1500	6750000	1078600	6600	20100	6.00	3384800	120600	3264200	130873800
24	1500	6750000	1078600	6600	20100	6.00	3187500	120600	3066900	133940700
25	1500	6750000	1078600	6600	20100	6.00	2990300	120600	2869700	136810400
26	1500	6750000	1078600	6600	20100	6.00	2793000	120600	2672400	139482800
27	1500	6750000	1078600	6600	20100	6.00	2595800	120600	2475200	141958000
28	1500	6750000	1078600	6600	20100	6.00	2398500	120600	2277900	144235900
29	1500	6750000	1078600	6600	20100	6.00	2201300	120600	2080700	146316600
30	1500	6750000	1078600	6600	20100	6.00	2004000	120600	1883400	148200000
TOT	127500	573750000	91683000	558000	1708500		158451000	10251000	148200000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.73	0.11	1.62	
MILLS PER KILOWATT-HOUR							2.49	0.17	2.32	
CENTS PER MILLION BTU HEAT INPUT							27.62	1.79	25.83	
DOLLARS PER TON OF SULFUR REMOVED							283.96	18.37	265.59	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							63660700	4411200	59249500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.61	0.11	1.50	
MILLS PER KILOWATT-HOUR							2.32	0.16	2.16	
CENTS PER MILLION BTU HEAT INPUT							25.78	1.78	24.00	
DOLLARS PER TON OF SULFUR REMOVED							265.36	18.38	246.98	

Table B-238. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel,
90% SO_2 removal; 8.6 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Startup bypass ducts and dampers	276,000	1.5
Electrostatic precipitators and inlet ducts (4 low temperature electrostatic precipitators including common feed plenum)	3,682,000	19.8
Sulfur dioxide converters and ducts (4 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	1,718,000	9.3
Reheat (8 direct oil-fired reheaters and 4 flue gas heat exchangers)	2,832,000	15.2
Fans (4 fans including exhaust gas ducts between fans and stack gas plenum)	1,923,000	10.3
Sulfuric acid absorbers and coolers (2 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between absorbers and fans)	5,875,000	31.6
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	314,000	1.7
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	493,000	2.7
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	574,000	3.1
Construction facilities	884,000	4.8
Subtotal direct investment	18,571,000	100.0
Engineering design and supervision	2,229,000	12.0
Construction field expense	2,414,000	13.0
Contractor fees	1,300,000	7.0
Contingency	2,043,000	11.0
Subtotal fixed investment	26,557,000	143.0
Allowance for startup and modifications	2,656,000	14.3
Interest during construction (8%/annum rate)	2,125,000	11.4
Total capital investment excluding catalyst	31,338,000	168.7
Catalyst	1,486,000	8.0
Total capital investment	32,824,000	176.7

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Remaining life of power unit, 25 yr.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-239. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(500-MW existing oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 59,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	90,000 liters	1.65/liters	148,500	1.34
Subtotal raw material			148,500	1.34
Conversion costs				
Operating labor and supervision	7,380 man-hr	8.00/man-hr	59,000	0.53
Utilities				
Fuel oil (No. 2)	8,690,000 gal	0.30/gal	2,607,000	23.43
Process water	4,245,000 M gal	0.03/M gal	127,400	1.14
Electricity	61,610,000 kWh	0.018/kWh	1,109,000	9.97
Maintenance				
Labor and material, .04 × 18,571,000			742,800	6.68
Analyses			31,400	0.28
Subtotal conversion costs			4,676,600	42.03
Subtotal direct costs			4,825,100	43.37
Indirect Costs				
Average capital charges at 15.3% of total capital investment			5,022,100	45.13
Overhead				
Plant, 20% of conversion costs			935,300	8.41
Administrative and marketing			343,600	3.09
Subtotal indirect costs			6,301,000	56.63
Total annual operating cost			11,126,100	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	195.74	2.16	3.18	34.55	568.82

[a] Basis:
Remaining life of power plant, 25 yr.
Oil burned, [illegible] bbl/yr, 9,200 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1979 operating costs.
Total capital investment, $32,824,000; subtotal direct investment, $18,571,000.
Working capital, [illegible].
[illegible]

Table B-240

CATALYTIC OXIDATION PROCESS, 500 MW EXISTING OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 32824000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5145400	19600	59900	6.00	14539800	359400	14180400	14180400
7	7000	32200000	5145400	19600	59900	6.00	14266700	359400	13907300	28087700
8	7000	32200000	5145400	19600	59900	6.00	13993600	359400	13634200	41721900
9	7000	32200000	5145400	19600	59900	6.00	13720500	359400	13361100	55083000
10	7000	32200000	5145400	19600	59900	6.00	13447400	359400	13088000	68171000
11	5000	23000000	3675300	14000	42800	6.00	11537500	256800	11280700	79451700
12	5000	23000000	3675300	14000	42800	6.00	11264400	256800	11007600	90459300
13	5000	23000000	3675300	14000	42800	6.00	10991300	256800	10734500	101193800
14	5000	23000000	3675300	14000	42800	6.00	10718200	256800	10461400	111655200
15	5000	23000000	3675300	14000	42800	6.00	10445100	256800	10188300	121843500
16	3500	16100000	2572700	9800	29900	6.00	8923500	179400	8744100	130587600
17	3500	16100000	2572700	9800	29900	6.00	8650300	179400	8470900	139058500
18	3500	16100000	2572700	9800	29900	6.00	8377200	179400	8197800	147256300
19	3500	16100000	2572700	9800	29900	6.00	8104100	179400	7924700	155181000
20	3500	16100000	2572700	9800	29900	6.00	7831000	179400	7651600	162832600
21	1500	6900000	1102600	4200	12800	6.00	5838500	76800	5761700	168594300
22	1500	6900000	1102600	4200	12800	6.00	5565400	76800	5488600	174082900
23	1500	6900000	1102600	4200	12800	6.00	5292300	76800	5215500	179298400
24	1500	6900000	1102600	4200	12800	6.00	5019200	76800	4942400	184240800
25	1500	6900000	1102600	4200	12800	6.00	4746100	76800	4669300	188910100
26	1500	6900000	1102600	4200	12800	6.00	4473000	76800	4396200	193306300
27	1500	6900000	1102600	4200	12800	6.00	4199900	76800	4123100	197429400
28	1500	6900000	1102600	4200	12800	6.00	3926800	76800	3850000	201279400
29	1500	6900000	1102600	4200	12800	6.00	3653700	76800	3576900	204856300
30	1500	6900000	1102600	4200	12800	6.00	3380600	76800	3303600	208160100
TOT	92500	425500000	67993000	259000	791000		212906100	4746000	208160100	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							3.13	0.07	3.06	
MILLS PER KILOWATT-HOUR							4.60	0.10	4.50	
CENTS PER MILLION BTU HEAT INPUT							50.04	1.12	48.92	
DOLLARS PER TON OF SULFUR REMOVED							822.03	18.32	803.71	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							98647300	2342100	96305200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							2.94	0.07	2.87	
MILLS PER KILOWATT-HOUR							4.32	0.10	4.22	
CENTS PER MILLION BTU HEAT INPUT							47.00	1.11	45.89	
DOLLARS PER TON OF SULFUR REMOVED							772.47	18.34	754.13	

Table B-241. Catalytic Oxidation Process
Summary of Estimated Fixed Investment[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 16.2 tons/hr 100% H_2SO_4)

	Investment, $	Percent of subtotal direct investment
Converter and absorber startup bypass ducts and dampers	642,000	2.3
Electrostatic precipitators and inlet ducts (4 high temperature electrostatic precipitators including common feed plenum)	3,370,000	12.2
Sulfur dioxide converters and ducts (8 converters including catalyst sifter, hopper, storage bin, conveyors, and elevators)	3,216,000	11.7
Heat recovery and ducts (4 direct oil-fired heaters and 4 fluid/air heaters including ducts between economizers and air heaters, and combustion air ducts and dampers between powerhouse and air heaters; investment credit for use of smaller air heaters included)	2,097,000	7.6
Fans (4 ID fans including exhaust gas ducts and dampers between ID fans and stack gas plenum)	1,856,000	6.7
Sulfuric acid absorbers and coolers (4 absorbers including mist eliminators, coolers, tanks, pumps, and ducts and dampers between air heaters and ID fans)	13,696,000	49.8
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	417,000	1.5
Utilities (instrument air generation and supply system, fuel oil storage and supply system, and distribution systems for obtaining process water, and electricity from power plant)	270,000	1.0
Service facilities (buildings, shops, stores, site development, roads, railroads, and walkways)	662,000	2.4
Construction facilities	1,311,000	4.8
Subtotal direct investment	27,537,000	100.0
Engineering design and supervision	2,754,000	10.0
Construction field expense	2,754,000	10.0
Contractor fees	1,377,000	5.0
Contingency	2,478,000	9.0
Subtotal fixed investment	36,900,000	134.0
Allowance for startup and modifications	3,690,000	13.4
Interest during construction (8%/annum rate)	2,952,000	10.7
Total capital investment excluding catalyst	43,542,000	158.1
Catalyst	2,814,000	10.2
Total capital investment	46,356,000	168.3

[a] Basis:
Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974.
Only pumps are spared.
Investment requirements for disposal of fly ash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.

Table B-242. Catalytic Oxidation Process
Total Average Annual Operating Costs—Regulated Utility Economics[a]

(1,000-MW new oil-fired power unit, 2.5% S in fuel; 90% SO_2 removal; 113,300 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Percent of total annual operating cost
Direct Costs				
Delivered raw material				
Catalyst	170,600 liters	1.65/liters	281,500	3.16
Subtotal raw material			281,500	3.16
Conversion costs				
Operating labor and supervision	7,890 man-hr	8.00/man-hr	63,100	0.71
Utilities				
Fuel oil (No. 6)	2,066,000 gal	0.23/gal	475,200	5.33
Heat credit	1,365,000 MM Btu	-1.60/MM Btu	(2,184,000)	(24.51)
Process water	322,000 M gal	0.08/M gal	25,800	0.29
Electricity	103,570,000 kWh	0.017/kWh	1,760,700	19.76
Maintenance				
Labor and material, .03 x 27,537,000			826,100	9.27
Analyses			49,100	0.55
Subtotal conversion costs			1,016,000	11.40
Subtotal direct costs			1,297,500	14.56
Indirect Costs				
Average capital charges at 14.9% of total capital investment			6,907,000	77.50
Overhead				
Plant, 20% of conversion costs			203,200	2.28
Administrative and marketing			504,200	5.66
Subtotal indirect costs			7,614,400	85.44
Total annual operating cost			8,911,900	100.00

	Dollars/ton 100% H_2SO_4	Dollars/bbl oil burned	Mills/kWh	Cents/million Btu heat input	Dollars/ton sulfur removed
Equivalent unit operating cost	78.66	0.92	1.27	14.63	240.93

[a] Basis:
Remaining life of power plant, 30 yr.
Oil burned, 9,731,500 bbl/yr, 8,700 Btu/kWh.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location, 1975 operating costs.
Total capital investment, $46,356,000; subtotal direct investment, $27,537,000.
Working capital, $286,100.
Investment and operating cost for disposal of fly ash excluded.

Table B-243

CATALYTIC OXIDATION PROCESS, 1000 MW NEW OIL FIRED POWER UNIT, 2.5% S IN FUEL, 90% SO2 REMOVAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 46356000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NET REVENUE, $/TON 100% H2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	9731500	37000	113300	6.00	13734500	679800	13054700	13054700
2	7000	60900000	9731500	37000	113300	6.00	13413100	679800	12733300	25788000
3	7000	60900000	9731500	37000	113300	6.00	13091700	679800	12411900	38199900
4	7000	60900000	9731500	37000	113300	6.00	12770300	679800	12090500	50290400
5	7000	60900000	9731500	37000	113300	6.00	12448900	679800	11769100	62059500
6	7000	60900000	9731500	37000	113300	6.00	12127500	679800	11447700	73507200
7	7000	60900000	9731500	37000	113300	6.00	11806100	679800	11126300	84633500
8	7000	60900000	9731500	37000	113300	6.00	11484700	679800	10804900	95438400
9	7000	60900000	9731500	37000	113300	6.00	11163300	679800	10483500	105921900
10	7000	60900000	9731500	37000	113300	6.00	10841900	679800	10162100	116084000
11	5000	43500000	6951100	26400	80900	6.00	10105800	485400	9620400	125704400
12	5000	43500000	6951100	26400	80900	6.00	9784400	485400	9299000	135003400
13	5000	43500000	6951100	26400	80900	6.00	9463000	485400	8977600	143981000
14	5000	43500000	6951100	26400	80900	6.00	9141600	485400	8656200	152637200
15	5000	43500000	6951100	26400	80900	6.00	8820200	485400	8334800	160972000
16	3500	30450000	4865800	18500	56700	6.00	8156800	340200	7816600	168788600
17	3500	30450000	4865800	18500	56700	6.00	7835400	340200	7495200	176283800
18	3500	30450000	4865800	18500	56700	6.00	7514000	340200	7173800	183457600
19	3500	30450000	4865800	18500	56700	6.00	7192600	340200	6852400	190310000
20	3500	30450000	4865800	18500	56700	6.00	6871200	340200	6531000	196841000
21	1500	13050000	2085300	7900	24300	6.00	6013400	145800	5867600	202708600
22	1500	13050000	2085300	7900	24300	6.00	5692000	145800	5546200	208254800
23	1500	13050000	2085300	7900	24300	6.00	5370600	145800	5224800	213479600
24	1500	13050000	2085300	7900	24300	6.00	5049200	145800	4903400	218383000
25	1500	13050000	2085300	7900	24300	6.00	4727800	145800	4582000	222965000
26	1500	13050000	2085300	7900	24300	6.00	4406400	145800	4260600	227225600
27	1500	13050000	2085300	7900	24300	6.00	4085000	145800	3939200	231164800
28	1500	13050000	2085300	7900	24300	6.00	3763600	145800	3617800	234782600
29	1500	13050000	2085300	7900	24300	6.00	3442200	145800	3296400	238079000
30	1500	13050000	2085300	7900	24300	6.00	3120800	145800	2975000	241054000
TOT	127500	1109250000	177252500	673500	2064000		253438000	12384000	241054000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							1.43	0.07	1.36	
MILLS PER KILOWATT-HOUR							1.99	0.10	1.89	
CENTS PER MILLION BTU HEAT INPUT							22.85	1.12	21.73	
DOLLARS PER TON OF SULFUR REMOVED							376.30	18.39	357.91	
PROCESS COST DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS							102227700	5328400	96899300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							1.34	0.07	1.27	
MILLS PER KILOWATT-HOUR							1.86	0.09	1.77	
CENTS PER MILLION BTU HEAT INPUT							21.42	1.12	20.30	
DOLLARS PER TON OF SULFUR REMOVED							352.63	16.38	334.25	

APPENDIX C

LARGE SCALE FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973 (COMPLETED, UNDER CONSTRUCTION, AND PLANNED) (11)

Utility company power station	New or retrofit	Size of FGD unit (MW)	Process vendor	Fuel and sulfur content	Status (start-up date)
Limestone Scrubbing					
Commonwealth Edison Will County No. 1	R	156	B&W	Coal, 3.5%	Operational (Feb. 1972)
Kansas City Power & Light, Hawthorn No. 4	R	100	CE	Coal, 3.5%	Operational (Aug. 1972)
Kansas City Power & Light, LaCygne Station	N	820	B&W	Coal, 5%	Operational (June 1973)
Arizona Public Service Cholla Station	R	115	Research Cottrell	Coal, 0.4%-1.0%	Under construction (Oct. 1973)
Detroit Edison St. Clair No. 6	R	180	Peabody Engineering	Coal, 3.7%	Under construction (Dec. 1973)
Southern California Edison (operating agent) Mohave Station	R	160	UOP	Coal, 0.5%-0.8%	Under construction (March 1974)
TVA Widow's Creek No. 8	R	550	TVA	Coal, 3.7%	Under construction (Jan. 1977)
Northern States Power Sherburne County No. 1	N	680	CE	Coal, 1%	Under construction (May 1976)
Public Service of Indiana, Gibson Station	N	650	CE	Coal, 1.5%	Planned (1976)
Northern States Power Sherburne County No. 2	N	680	CE	Coal, 1%	Planned (May 1977)
Lime Scrubbing					
Union Electric Co. Meramec No. 2	R	140	CE	Coal, 3%	Abandoned (Sept. 1968)
Kansas Power & Light Lawrence No. 4	R	125	CE	Coal, 3.5%	Operational (Dec. 1968)
Kansas Power & Light Lawrence No. 5	N	430	CE	Coal, 3.5%	Operational (Nov. 1971)
Kansas City Power & Light, Hawthorn No. 3	R	100	CE	Coal, 3.5%	Operational (Nov. 1972)
Louisville Gas & Electric Paddy's Run No. 6	R	70	CE	Coal, 3%	Operational (April 1973)
Duquesne Light Co. Phillips Station	R	100	Chemico	Coal, 2%	Under construction (Nov. 1973)
Southern California Edison (operating agent) Mohave Station	R	160	SCE/Stearns-Roger	Coal, 0.5%-0.8%	Under construction (Dec. 1973)
Ohio Edison/Mansfield Station (2 units)	N	1650	Chemico	Coal, 4.3%	Under construction (early 1975)
Montana Power Colstrip No. 1 & 2	N	720	CEA	Coal, 0.8%	Under construction (May 1975)
Columbus & Southern Conesville No. 5 & 6	N	750	Not selected		Planned (1976)

Utility company power station	New or retrofit	Size of FGD unit (MW)	Process vendor	Fuel and sulfur content	Status (start-up date)
		L/LS Not Selected			
Salt River Project Navajo No. 1	N	750	Not selected	Coal, 0.5%-0.8%	Construction start, Nov. 1974 (Mar. 1976)
Salt River Project Navajo No. 2	N	750	Not selected	Coal, 0.5%-0.8%	Construction start, Oct. 1975 (Oct. 1976)
Arizona Public Service Four Corners No. 1	R	175	Not selected	Coal, 0.75%	Construction start, Oct. 1975 (Oct. 1976)
Arizona Public Service Four Corners No. 2	R	175	Not selected	Coal, 0.75%	Construction start, Nov. 1975 (Dec. 1976)
Southern California Edison (operating agent) Mohave No. 1 & 2	R	1180	Not selected	Coal, 0.5%-0.8%	Planned (Dec. 1976)
Arizona Public Service Four Corners No. 3	R	229	Not selected	Coal, 0.75%	Construction start, June 1976 (Mar. 1977)
Salt River Project Navajo No. 3	N	750	Not selected	Coal, 0.5%-0.8%	Construction start, Mar. 1976 (Mar. 1977)
Arizona Public Service Four Corners No. 4	R	800	Not selected	Coal, 0.75%	Construction start, Sept. 1975 (Apr. 1977)
Arizona Public Service Four Corners No. 5	R	800	Not selected	Coal, 0.75%	Construction start, Nov. 1976 (June 1977)
		Magnesium Oxide Scrubbing			
Boston Edison Mystic No. 6	R	150	Chemico	Oil, 2.5%	Operational (April 1972)
Potomac Electric & Power Dickerson No. 3	R	100	Chemico	Coal, 2%	Operational (Sept. 1973)
Philadelphia Electric Eddystone No. 1	R	120	United Engineers	Coal 2.5%	Under construction (Dec. 1973)
		Other SO_2 Control Systems			
Catalytic Oxidation (Cat-Ox) Illinois Power Co. Wood River No. 4	R	110	Monsanto	Coal, 3.2%	Operational (Oct. 1972)
Wellman-Lord Northern Indiana Public Service D. H. Mitchell No. 11	R	115	Davy Powergas/ Allied Chemical	Coal, 3.5%	Under construction (early 1975)
Aqueous Sodium Base Scrubbing Nonregenerable Nevada Power Reid Gardner No. 1 & 2	R	250	CEA	Coal, 0.5%-1.0%	Under construction (Dec. 1973)
Nevada Power Reid Gardner No. 3	R	125	CEA	Coal, 0.5%-1.0%	Under construction (1975)
Dry Adsorption Indiana & Michigan Electric Tanner's Creek Station	R	150	B&W/Esso	Coal	Under construction (1974)

Utility company power station	New or retrofit	Size of FGD unit (MW)	Process vendor	Fuel and sulfur content	Status (start-up date)
Process Not Selected					
Public Service of New Mexico San Juan No. 2	R	100	Not selected	Coal, 0.8%	Planned (Nov. 1974)
Potomac Electric & Power Chalk Point No. 3	N	630	Not selected	Oil	Planned (1975)
Potomac Electric & Power Chalk Point No. 4	N	630	Not selected	Oil	Planned (1976)
Potomac Electric & Power Dickerson No. 4	N	800	Not selected	Coal, 2%	Planned (1976)
Potomac Electric & Power Dickerson No. 5	N	800	Not selected	Coal, 2%	Planned (1977)